

Final Workshop Report:
Interim Emissions Performance Standard Program Framework, R.06-04-009
June 21-23, 2006

Prepared by Commission Staff, October 2, 2006

The California Public Utilities Commission (“CPUC” or “Commission”) convened a three-day workshop in its climate change policy proceeding, R.06-04-009, on June 21-23, 2006 in San Francisco. This workshop considered the design and implementation structure of an interim emissions performance standard (“EPS”) program prior to implementation of a greenhouse gas (GHG) cap that would apply to the three major investor-owned electric utilities (“IOUs”)¹, its jurisdictional energy service providers (“ESPs”), and community choice aggregators (“CCAs”) that operate within an IOU’s territory. This Report outlines the background and purpose of the workshops, reviews participants’ comments on key points, summarizes the advantages and disadvantages that participants attributed to key issues associated with an interim EPS program, and includes a revised version of the staff proposal for an EPS program. Appendices include a list of the workshop participants, a summary of the written comments on the Draft Workshop Report, the data requested at the workshop and subsequent responses, the revised staff proposal posed for post-workshop comments, questions posed to parties for post-WS comment, and the text of SB1368.

For purposes of clarity, “Final Proposal” or “Final Staff Proposal” refers to the staff proposal submitted today as part of the Final Report. “Revised Proposal” or “Revised Staff Proposal” refers to the staff proposal circulated for comment as part of the Draft Report issued on August 21, 2006. For reference, this revised proposal is included as Appendix H.

This Final Report incorporates opening comments on the Draft Workshop Report submitted by parties on September 8, 2006 and reply comments submitted on September 15, 2006. Where appropriate, staff has also incorporated the relevant statutory guidelines and requirements adopted in SB1368 and AB32 as they relate to the design of an interim EPS. These pieces of legislation were signed into law on September 29 and September 27, 2006, respectively.

Throughout this report, we use the term “greenhouse gas”² or “GHG” (rather than “carbon” or “CO2”) to refer to the types of emissions that would be addressed in an EPS, even though CO2 reductions may be the primary focus in the near term. This recognizes that the full scope of GHG emissions will ultimately need to be included in the strategies to mitigate climate change.

¹ We use the term “IOUs” to refer collectively to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), the utility respondents to the this proceeding.

² Primary greenhouse gases influenced by humans are carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Visit the EPA’s website at <http://yosemite.epa.gov/oar/globalwarming.nsf/content/emissions.html> for a more thorough overview of GHGs.

I. Background and Purpose of the Workshop

In the October 6, 2005 GHG Policy Statement, the Commission describes a GHG emissions performance standard that would limit the GHG emissions levels for all new utility-owned generation and all long-term procurement contracts to “no higher than the GHG emissions levels of a combined-cycle natural gas turbine.”

The Commission’s objective in scheduling this workshop was to identify key issues to consider when contemplating an EPS, and to develop an EPS program proposal that would incorporate policy, design and implementation issues identified by parties and staff. The EPS discussion and proposal was limited to an interim GHG EPS program intended to serve as a near-term bridge to the load-based GHG cap adopted by the Commission in D.06-02-032, and to the extent possible, form consensus among parties. The development of an interim GHG EPS is identified as “Phase 1” of R.06-04-009, with “Phase 2” focusing on design and implementation of a load-based cap.

As discussed at the May 10, 2006 Pre-Hearing Conference on the matter, and subsequently described in the June 1 Ruling, Phase 1 will address the following key questions:

- (a) Should the Commission adopt an interim GHG EPS to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032?
- (b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose?

The language of the OIR indicates that the Commission did not intend to restrict the design of the performance standard to the one specifically set forth in the 2005 GHG Policy Statement. In the context of Phase 1, however, the specific purpose of an interim performance standard may dictate many of the relevant design and implementation parameters. As discussed at the PHC, certain “bells and whistles” (e.g., offsets) to a performance standard that the Commission may wish to consider in the context of a load-based cap do not appear to be feasible in the context of an interim standard that needs to be put in place quickly.

Accordingly, deviations from the performance standard design set forth in the 2005 GHG EPS Policy Statement may be considered in Phase 1, but only to the extent that such deviations would not significantly delay the implementation of an interim EPS.

To help focus party preparation for this workshop, the assigned Administrative Law Judge (Judge Gottstein) circulated a proposed agenda and pre-workshop questions prepared by CPUC staff on May 31, 2006. Judge Gottstein directed interested parties to file pre-workshop comments in response to the questions posed and to identify other issues, if any, that the CPUC should take into consideration at the workshops. A list of those parties filing opening and reply comments on the Draft Workshop Report is included in the summary of those comments presented in Appendix A of this report.

Approximately 90 individuals, representing about 50 different stakeholders, attended one or more days of the workshop. Appendix B presents a list of these workshop participants. This workshop report cannot fully reflect all of the discussion throughout the three-day workshop. Instead, the sections entitled “Workshop Participant Comments” in the body of this report are intended to highlight the major issues raised during the discussion, rather than to present a detailed summary of each participant’s position.

II. Workshop Structure and Scope

Based upon the proposed agenda included in the June 1 Ruling and pre-workshop comments, staff structured the workshop to address three overlapping categories relevant to the design and implementation of an EPS: 1) Policy Overview and Basic EPS Structure, 2) Standard-setting and Implementation Details, and 3) Design Summary, Implementation Issues, and Next Steps. In addition, a staff straw proposal was presented for discussion on Days 2 and 3. Workshop discussion was structured to identify policy issues of primary concern when considering whether to pursue an EPS program, followed by discussion of key design and implementation issues associated with an EPS program.

On May 31, 2006 CPUC staff further clarified the scope of the workshop by including pre-workshop questions (see Appendix C). On June 1, 2006 Judge Gottstein’s Ruling³ provided additional direction on the scope of phase 1 and indicated the two primary umbrella issues to be addressed: (a) Should the Commission adopt an interim GHG emissions performance standard to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032; and (b) If the Commission elects to adopt such a standard, how should it be designed and implemented so that it can be put in place quickly to serve this purpose? Judge Gottstein also asked parties to present their best available assessment costs, benefits, and co-benefits.

The purpose of this workshop was strictly to discuss phase 1 issues which are limited to the concept and design of an interim EPS. Phase 2 issues related to development and implementation of a greenhouse gas cap were expressly not included for discussion at the workshop, or at the phase 1 Pre-Hearing Conference or in subsequent materials. Phase 2 issues will be addressed in that phase of the proceeding.

CPUC staff and consultant⁴ began the workshop with an overview of the major areas to be considered in each of the three days: policy overview and basic EPS structure (Day 1); standard-setting and implementation details, including discussion of a staff straw proposal (Day 2); EPS design summary and implementation details, including continued discussion of the staff straw proposal (Day 3)⁵. The data requested at the workshop are attached as Appendix E. In the sections below, we summarize the workshop discussion

³ <http://www.cpuc.ca.gov/EFILE/RULC/56888.pdf>

⁴ Richard Cowart of the Regulatory Assistance Project assisted CPUC staff in framing the workshop and developing the straw proposal, and led the workshop discussions.

⁵ The agenda for the workshop is posted at www.cpuc.ca.gov/static/hottopics/1energy/ghgperformancestandardworkshopagenda+_june+21_23.pdf

on a day-by-day basis. Readers are encouraged to refer to the materials in the appendices as they review this summary.

III. Policy Overview and Basic EPS Structure Discussion (Day 1)

CPUC staff provided an overview of the context for consideration of an interim EPS, and a brief overview of the existing EPS Policy Statement. Emphasis was placed on pursuing focused discussion to identify areas of agreement, where possible, and to identify key issues associated with consideration and/or design of an interim EPS.

The structure of discussion followed the order of questions posed for pre-workshop comment. The responses have been categorized and summarized based upon the flow of discussion during the workshop days.

A. Workshop Participant Comments on Policy Overview Questions: General Considerations

Staff then posed the following “Policy Overview” questions for discussion to identify the key areas of agreement and of concern.

1a. Should the Commission adopt an interim EPS to guide ongoing electric procurement decisions pending adoption of a long-term cap and trade program? Identify principal policy arguments, pro and con

Responses to Q1a

- The existing carbon adder policy adopted and implemented by the CPUC makes an EPS unnecessary as it achieves the same goal of preventing backsliding to higher emitting resources than those currently included in the IOU and ESPs portfolio mix. (IEPA)
- An EPS supports the Governor’s Executive Order setting GHG emission reduction goals. An EPS should stay in effect even after a cap and trade program is implemented. (NRDC)
- The adder is complimentary to EPS but does not replace. Open question as to how an EPS might interact with reliability risks. IOUs should include an EPS scenario with existing procurement plans. (TURN)
- The CPUC could increase the adder amount to meet some of the same near-term goals as an EPS. However, an EPS essentially requires existing ratepayers to pay for externalities associated with GHGs while the existing adder places the bulk of the burden on future generations as it does not take into account costs beyond a certain price point and is advisory only. The adder still allows high emitting plants into the procurement mix whereas an EPS sets a minimum standard. (CEC)
- The CPUC already has oversight over new LT contracts anyway so EPS is unnecessary. (SCE)

- The CPUC should set clear requirements for procurement up front. Before going through an involved RFP process requiring time and money, LSEs should know with certainty the CPUC's contract and generation requirements. Waiting for the CPUC to weigh in at the end of the process is counter-productive. Issues: costs, reliability, support adder. Concerned about excluding too many resources. (PG&E)
- The effect of an EPS impact would be insignificant as the CPUC already has existing policies that prevent backsliding such as the RPS and EE. (EPUC)
- The CPUC has oversight of long-term procurement. LSEs need clear and unambiguous signal to prevent investment in new power plants and contracts of highest emitting variety. New coal is an issue. The EPS provides the clear signal needed to ensure clean energy investment. (GPI)
- The adder is problematic because it's difficult to determine the "right" value. Development of an interim EPS may interfere with development of a cap and trade program, and new technologies may be disincented. Further, relying on the knowledge by LSEs that a cap will be in place by a given near-term date can give sufficient incentive to contract for low-emitting resources now. (SF Community Power)
- Investment decisions are happening now in the interior west including new non-advanced coal facilities and transmission to bring coal to California. A carbon adder is anticipated compliance cost, whereas an EPS looks at an actual emissions threshold. (WRA)
- The carbon adder allows for consideration of other attributes- reliability, costs, etc, that an EPS does not. EPS seems to draw a line in the sand. (SDG&E)
- Ongoing monitoring of contracts and investments would create uncertainty and significantly affect market. (IEPA, PG&E)
- An EPS should include dispatch consideration and peakers. (League of Women Voters)
- An EPS is overly prescriptive regarding technology choice. (Constellation)

1b. If the Commission decides to adopt an interim EPS, what goals are most important in guiding its design and implementation?

Responses to Q1b

- The purpose of an EPS is to prevent investment and contracting with resources that are higher emitters than what we have in the system today and therefore prevent "backsliding." CA is the load center in WECC. Need to lead. (GPI)

- General concerns expressed regarding the possibility of developing overly prescriptive policies. (EPUC)
- EPS necessary to prevent the increasing emissions prior to implementation of a future cap. Encourages technological innovation. (NRDC)
- EPS should be comprehensive and apply to all LSEs. (PG&E)
- Don't include ESPs. Emissions are negligible from ESPs and long-term contracting is limited. (AReM)
- EPS should be designed to transition well to / integrate with a cap. (SF Community Power)
- Appropriate design depends on whether EPS would apply to existing and/or new facilities. (SCE)
- Need to know how an EPS would link to existing procurement policies. (Constellation)

B. Workshop Participant Comments on Basic EPS Structure

Staff then posed the following EPS Basic Structure questions for discussion to identify the key areas of agreement and of concern.

2. If an interim EPS is adopted, to which Load Serving Entities (LSEs) should it apply?

Responses to Q2: To which LSEs should an interim EPS apply?

- Energy Service Providers (ESP) should not be included in an EPS program as their procurement process is not the same as IOUs and they represent a small portion of total load. Implementation delays and extra costs would be likely if ESPs were required to participate. (AReM)
- ESPs can have a significant impact on market, especially if wholesale costs drop and as DWR contracts expire, ESPs can sign up more contracts. The argument that ESPs don't enter into significant long-term contracts is not persuasive. If they don't enter into long-term contracts, then ESP compliance with the program would be negligible. If they do enter into significant long-term contracts, they should be included. Either way, it makes sense to include them as part of an EPS.
Prefer comprehensive statewide policy including munis. If munis are not included, it then creates competitive problems for utilities statewide. Need to understand impacts of CA energy markets if munis are exempt from program Programs need to be at minimum statewide, and policies need to coordinate with legislation. (PG&E, SCE)

- The CPUC Long-Term Procurement Docket has teed up the issue for Phase II as to how ESPs may be required to come into procurement process. (CPUC Energy Division)
- Open issue of how to deal with system contracts and allocation for multi-state, multi-jurisdictional entity. (Mid-American/PacifiCorp)
- The program should focus on the public good and be applied to munis also. (League of Women Voters)
- Munis do not need to be included in an EPS program as they are more responsive than IOUs. (NorCal Power Agency)
- CPUC sets standard that creates pressure on other entities, e.g. munis. The program should aim to accomplish all that it can for CPUC jurisdictional LSEs. (GPI)
- An EPS program needs to be coordinated with legislation. (IEPA)

3. Over what time frame should an interim EPS be implemented?

Responses to Q3: Over what timeframe should an interim EPS remain in place?

- Current CPUC procurement process reviews a significant number of short-term contracts. The number of contracts of 5 years and greater are much more limited. Currently reviewing one long-term contract submitted by PG&E. Anticipate SCE will soon file long-term contracts with the CPUC as well. (CPUC Energy Division).
- EPS should remain in place until a more comprehensive program is implemented. Note that the program doesn't necessarily have to be a CPUC program. (PG&E)
- The CPUC should not pursue an EPS program and should instead wait for state, regional, or federal action. (EPUC)

4. To which power sources should an EPS apply?

Responses to Q4: To which power sources should an interim EPS apply?

- Program should include contracts/facilities of 5 MW and greater as that is consistent with SGIP. The EPS should apply to all long-term contracts including IOU owned, repowered facilities. IGCC should be included if sequestration is part of the technology. (NRDC)

- Program should include contracts of 25MW for greater consistency with RGGI, CARB. Some exemptions should be made based upon size. (EPUC)
- Peakers should not necessarily be exempted as that may incent more peakers into the system. (DRA, League of Women Voters)
- Air Boards won't let more peakers into the system so DRA's concern is moot. Also applying standard to peakers to get additional savings not fair since goal is to prevent backsliding. (PG&E)
- Including small peakers in an EPS would be administratively challenging. (AReM)
- In-state, out-of-state, existing, new, and in state renewals of contracts should be included. (Redefining Progress)
- Repowering needs to be defined. (PG&E)
- Existing plants should not be included. Only new plants should be part of the program. (SCE)
- New long-term contracts should be included. (GPI)
- Concerns raised about additional costs to ratepayers regarding resource adequacy in meeting an interim EPS. (Constellation)
- If existing contracts covered then concern that IOUs are advantaged over IPPs because they do not enter into contracts with their own generation. (Constellation)
- If existing plants are grandfathered under the EPS, then risk losing the motivation to retire, repower, or otherwise invest in cleaner resources. (CEC)
- QFs should be exempt because IOUs are required to take those contracts. In addition, combined heat and power (CHP) should be exempt because of dual use of fuel. Some discussion of a proposal⁶ to calculate emissions from co-generation facilities. (EPUC)
- Five-year or longer term of contracts should be included as that is consistent with a carbon adder and long-term procurement policies. (PG&E).
- If standard is 5 years, there is a concern that plants will be contracted for shorter periods in order to bypass the EPS. (UCS).

⁶ The cogeneration calculation presented by Energy Producers and Users Coalition and Cogeneration Association of California is posted at:
www.cpuc.ca.gov/static/energy/electric/climate+change/cogen+calculationpresentation.pps

IV. Standard-setting and Implementation Details Discussion (Day 2)

CPUC staff began Day 2 by moving directly into discussion and shaping of an interim EPS program including definition of the standard, compliance and monitoring, and flexible compliance options. The agenda continued to follow the order of the pre-workshop comment questions.

In the afternoon session, a staff straw proposal was provided for discussion. The straw proposal was further discussed and finessed the following day.

A. Workshop Participant Comments on Standard-setting and Implementation Details

Question 5: What is the standard, and the technical basis for setting it?

Responses to Q5:

- The standard should be based upon emissions per MW equal to a “well functioning” CCGT. CPUC should coordinate with CEC to determine an appropriate CCGT emissions factor. IGCC plus sequestration should be considered in meeting the standard. (NRDC)
- Baseload definition could use 60% as cutoff capacity factor, but provisions for reliability issues should be included. (PG&E)
- Average of CEMS/eGRID data (excluding outliers) could be used as an emissions factor proxy. Alternatively, net system average could also be a solution. (CEC)
- CEC and NRDC proposals do not address actual emissions due to efficiencies, or lack of, associated with transmission/distribution/location issues. (IEPA)
- Need to have a shared definition of CCGT. (Sempra)
- Objects to “well functioning” as part of the metric proposed by NRDC. SDG&E wants technology to be the standard with multi-attributes for varying technologies. (SDG&E)
- Baseload renewables should be included. Renewable Energy Credits need to come with purchase, or have emissions factor assigned. Standard should be more aggressive than a CCGT emissions average to meet the Governor’s targets. (CRS)
- More important to determine the goal of the program but don’t name specific technology. (EPUC)
- CCGT should be the standard. (GPI)

- If a technology based gateway screen is used, then the operational aspects of a plant may be unimportant. Intensity per MWh should be the metric. (CCAR)
- How to handle repowering of existing plants? (Redefining Progress)
- One single standard should be used for new and repowered plants. (IEPA)
- Single standard should be applied to all resources. (GPI, SDG&E)
- Qualifying facilities should not be included since IOUs are required to take their power. (PG&E)
- Should use the 95th percentile standard- best available not just an average standard of existing plants. (Redefining Progress)
- Standard should be set in a way that avoids gaming and makes sure that unspecified contracts are accurately accounted. (CRS)
- Should have an R&D exemption to encourage other technologies. (EPUC)

Question 6: How can compliance with the standard be determined?

Participants generally agreed that the CPUC should provide an initial review of baseload contracts eligible for the EPS. Once those contracts are approved, no further review would be necessary. Parties understood that underlying resources might have varying heat rates, that dispatch is beyond an LSE's control, and the interim EPS would be a rough screen. The concept was to implement something in the near-term that would address the primary goals of an EPS.

Key issues to address focused on unspecified resources and repowering of units. The majority of participants agreed that one standard should apply to all resources- as opposed to one standard for new resources, and another for existing and repowered resources. Various proxy options for unspecified resource emission factors were discussed; 1) average emissions from coal generation, 2) WECC average, 3) geographical averages, and 4) CEC's CA net system power average which is the average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a CA utility.

Responses to Q6:

- Operational and dispatch impacts should also be included in the program. (League of Women Voters)
- System sales should be limited to less than 5 years and therefore would not hit the gateway. (EPUC)

- No time/duration limit should be imposed upon unspecified resources. (AReM)
- Unspecified resources are an issue with an EPS and also with a cap. Eventually, we need to deal with it, so we should deal with it now. (GPI)
- Is there a potential role in assigning a value to unspecified resources using CCAR or some other methodology? (AReM)
- In a case of “blended” baseload contracts, if one resource does not make it, then the blend should not qualify. (NRDC, Redefining Progress)
- NRDC’s proposal could penalize wind and other renewables. (AReM)
- If the proposed contract as a whole passes the test, then it should qualify. (Semptra)
- For unspecified resources, apply emissions factor from the region from which the energy is produced since in most situations it is known where the power is coming from. If average emissions from coal is used as a proxy, it creates a perverse incentive to actually purchase coal. (PG&E)
- For unspecified resources, average emissions from coal should be the default. (NRDC)
- SCE is not currently doing any long-term deals for unspecified resources. Not sure that geographical average is the right approach as an LSE might know the delivery point for energy, but doesn’t necessarily know what is behind it. (SCE)
- Renewable power that enters into the system with its Renewable Energy Credits (RECs) assigned to another entity, should not be treated as renewable. Instead, it should be treated as “null” power and assigned a system average of some sort to avoid double counting of renewable attributes. (CRS)

Questions posed by CPUC to parties at this point:

1. Can you “green up” power that would not otherwise qualify?
 2. Can you use “null” renewables (renewables that have been stripped of RECs)
- Don’t penalize renewables at this point. We want to encourage as many renewables into the system as we can. We should bring them in as clean, especially since CPUC jurisdictional LSEs cannot currently trade RECs so the double counting issue for them is not significant. (GPI)
 - Null renewable power should not be considered a renewable resource as the renewable attributes have been sold to another entity. (CRS)

Question 7: What compliance and monitoring procedures and monitoring are needed?

Responses to Q7:

- IOUs are required already to demonstrate compliance to the CPUC. This would be an additional component of the approval process. Once approved, the IOUs' contracts would be considered compliant, and subject to audits and spot checks. (PG&E, Constellation)
- LSEs could do a simple resource adequacy filing after the fact. Alternatively, they could provide an advance filing to the CPUC signaling their activity. (AReM)
- As long as the screen is in effect and if all contracts qualify, then no need to do work after the fact. (GPI)
- Require supply contracts to commit to delivery terms. If it does not happen, then the suppliers are in breach. (IEPA)
- Might need to check that the plants are running in the way they were supposed to. (Redefining Progress, CCAR)
- Cogen plants have to show efficiency demonstration to FERC in order to be approved. If things change, they have to be recertified by FERC. Regarding ongoing compliance, if marketer changes mix, they are on the hook financially. (EPUC)
- Emissions ought to be specified as condition of contract. (NRDC)

Question 8: Flexible compliance options

Responses to Q8:

- No safety valve needed as long as the screen allows for case by case review. (PG&E)
- Safety valve may make sense. Want to see offsets as part of a longer term emissions policy, but not sure if needed with interim EPS. (SCE)
- No offsets should be included in the EPS. (NRDC)
- Any early action credits should be addressed in Phase II implementation of a load-based cap. (IEPA, NRDC)
- Sempra's recent experience demonstrates difficulty of using offsets to "clean" energy resources that are large emitters. Their recent attempt to do so was unsuccessful due to concerns about 3rd party vendors. (Sempra)

- This program should be coordinated with current bills pending before the CA legislature. (PG&E)

B. Staff Straw Proposal

On the afternoon of Day 2, staff introduced a straw proposal based upon the workshop discussion thus far. That straw proposal, including the modifications made based upon discussion at the workshop, is described below. Discussion of post-workshop comments and an updated staff proposal reflecting comments is addressed in a subsequent section.

1. Design Goals for the EPS

- a. Prevent backsliding and commitments that will make future GHG reductions more difficult
- b. Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
- c. Reliability:
 - i. short-term: do not force shutdown of essential facilities
 - ii. long-term: consider risks of relying on high emitting resources
- d. Administrative simplicity

2. Timeframe

- a. Coordinate with procurement proceeding, but adopt now
- b. Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

3. To Which LSEs does the EPS apply?

- a. Apply to all jurisdictional LSEs (including ESPs and CCAs)
- b. Create ESP process to address ESP procurement related to this program
- c. Do not delay pending legislation regarding publicly-owned utilities
- d. Develop a filing/approval process for multi-jurisdictional utilities, including a protocol for allocating emissions among resources serving multiple states

4. Program Screens

- a. The EPS standard will be applied on a “gateway” basis, at the time a LSE’s commitment (build or buy) is proposed.
- b. The standard will be applied to the reasonably projected emissions rate from the supply source over the term of the commitment
- c. “Covered resources” are resources with a reasonably projected average annual capacity factor of 60% or greater.

5. Which Power Sources are covered?

- a. Applied to utility owned **new generation, repowering or new/renewal contracts**
- b. All new and renewal contracts and investments in “covered resources” of **five years or longer**
- c. Applied to **baseload and intermediate or “shaping” facilities with annual average capacity factor of 60% or greater**
- d. Size threshold:
 - For **specified facilities (built or under contract): 25 MW or greater** delivered to the grid;
 - For **unspecified resource/facilities under contract: all sizes**
- e. Application to QFs addressed in legal briefs
- f. Self-generation is covered (size threshold determined based on amount delivered to grid; cogeneration thermal load credit calculated, see below).
- g. Renewables are covered, emissions factors can be demonstrated at the time of review (includes biomass, waste-to-energy, geothermal, etc.)
- h. Reliability exemption considered on a case-by-case basis

6. What is the Standard and How Determined?

- a. Emissions standards based upon CCGT performance
 - i. Higher standard for new facilities : high-performing new CCGT
 - ii. Moderate standard for existing facilities and repowering – keyed to performance of existing CCGT fleet
 - iii. Allowance for cogen thermal load
- b. Potential R&D exemption on a case-by-case basis (e.g., permit advanced coal facilities that have the capacity to capture and store carbon dioxide “safely and inexpensively” as described in the GHG Performance Standard Policy Statement?).

7. How to apply the standard to units and contracts

- a. For single unit specific contracts: applied on facility basis
- b. For multi-unit contracts: each covered unit must qualify
- c. Baseload renewable product with firming fossil (that qualifies as a “covered resource”) -- applied to baseload blend average. If firming unit is unspecific impute appropriate emissions factor.
- d. Treatment of null renewable power? Not addressed at this juncture.
- e. Unspecified resource contracts: apply appropriate emissions factor. Choices are:
 - i. WECC system average
 - ii. Appropriate geographic average (e.g., NW is different from SW)
 - iii. CEC “Net System Power” calculations
 - iv. Default to coal emission rates

8. Monitoring and Enforcement

- a. CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

9. Offsets, Safety Valves, and other flexibility devices

- a. No offsets or market price safety valves
- b. Case-by-case “safety valve” upon application and CPUC review for reliability only.

C. Workshop Participants Comments on the Staff Proposal (Days 2 and 3)

- The proposal should not apply to existing resources. (SCE, PG&E)
- The goals of the program are not clear. What are the risks that the CPUC is attempting to address? (Constellation)
- Not sure how this proceeding comports with the procurement proceeding. (SCE, Sempra)
- Not clear how to address multi-jurisdictional LSEs. (PacifiCorp)
- How will IOU new generation be addressed? (PG&E, IEPA)
- Proposal needs to include language relevant to the delivery to the grid to address co-generation produced power. (EPUC)
- Baseload definition should be more aggressive. (GPI)
- Projections should be based on an average year. (PG&E)

V. Data Needs (Day 3, continued)

The morning of day three continued the discussion of the staff proposal and modifications as described above. In the early afternoon, the discussion shifted to focus on high-level data that the CPUC needs to assess the essential impacts of an interim EPS. The following list of data was requested after which the workshop concluded. Responses to the assigned data requests are posted at www.cpuc.ca.gov/static/energy/electric/climate+change.

Based upon the responses provided to the service list, staff has made some modifications and updates to the original staff proposal. Specific discussion of findings is included in Section VI below.

FINAL

At the workshop, the IOUs (PG&E, SDG&E, SCE) and other workshop participants agreed to prepare, and provide to the service list, the information/analysis on topics related to the threshold policy issue and implementation design considerations for an interim EPS, as follows:

1. The size of the potential IOU procurement needs that would be covered by an interim EPS. The IOUs and the CEC are working on a common format for this information and will be providing the format to staff by July 7. By July 11, both redacted (public) and unredacted versions of this information will be provided to staff. The intent is to provide to the service list as much publicly available data on this topic as possible.

2. Analysis around the definition of "covered resources:" What proportion of GHG emissions from long-term commitments would be excluded/included if the threshold for review is 60% average annual capacity factor vs. 50%, 70% or 80%? The IOUs will be providing this information to staff by July 11th.

3. Graph/Schematic of representative heat rates/emission rates for different types of facilities, for the purpose of considering the level of the "moderate" and "high" EPS thresholds for existing/new facilities under the staff Straw Proposal, or alternative approaches. The IOUs and other workshop participants agreed to coordinate on this document, due July 11 to staff.

4. Size of potential ESP procurement. SCE and AReM are working on this information that will be submitted to staff by July 14.

5. Emission factors for unspecified resources. CEC staff will provide the WECC regional emissions average, sub-region averages and the "net system" average figures to staff by July 11.

6. Potential new sources of power (new projects coming on line) proposed for potential sale to California IOUs. CEC, WRA, Constellation and PacifiCorp agreed to pull together the data available on this issue, and provide it to staff by July 11.

In addition, at the workshop several participants agreed to coordinate the development of the following information to present in their post-workshop comments (jointly, if possible):

a. How one would calculate the net emissions rates from renewables (GPI, PG&E, NRDC and others)

b. The formula for a cogeneration thermal credit calculation, and whether it is consistent with the CARB approach: (EPUC circulating to others before comments are due)

c. Protocol for assigning "covered resources" to California for multi-jurisdictional utilities and other implementation issues unique to multi-jurisdictional LSEs (PacifiCorp, WRA).

VI. Comments on the Draft Workshop Report, Staff Discussion and Recommendations

Parties were directed to file comments on the Draft Workshop Report as described in Appendix F. For reference, the revised staff proposal as presented in the Draft Report for comments is included as Appendix H. In addition, Appendix A provides a summary of parties' comments on the revised staff proposal. This section summarizes those comments and identifies key outstanding issues. Each section concludes with a brief summary of staff recommendations on those issues. Rather than attempt to summarize each party's comments in full in this Report, staff will focus on areas of broad agreement, specific debate and/or concern, new recommendations for modification of the staff proposal that were not included in the discussion at the workshop, and other issues of key concern.

Seventeen parties provided comments on September 8, 2006. Those parties are:

- PG&E
- SDG&E and Southern California Gas Company (SoCalGas)
- SCE
- PacifiCorp
- Constellation
- Calpine
- Independent Energy Producers Association (IEPA)
- San Francisco Community Power (SF Power)
- Cogeneration Association of California and the Energy Producers and Users Coalition (EPUC/CAC, filing jointly)
- Center for Energy and Economic Development (CEED)
- NRDC/UCS/TURN/Western Resource Advocates (WRA) (filing jointly)
- Division of Ratepayer Advocates (DRA)
- Carson Hydro Project
- Alliance for Retail Energy Markets (AReM)
- Western Resource Advocates (WRA)
- California Cogeneration Council (CCC)
- Green Power Institute (GPI)

Key concerns and suggestions are identified below using the questions and format of the directions for post-workshop comments.

A. Threshold Issue: Should the Commission adopt an interim EPS?

Q1 and Q2. Should the Commission adopt an interim EPS? Why or why not? Do you generally support the “gateway” approach to the standard proposed in the revised staff proposal?

Parties' perspectives initially varied significantly on this issue. Several parties supported the interim EPS as described in the staff proposal primarily because 1) it sends a clear signal and regulatory certainty regarding long-term contract requirements, and 2) given

the existing procurement requirements, the proposed EPS is unlikely to impose significant burden upon LSEs to comply.

Other parties opposed the concept of an EPS on the grounds that it would largely be largely duplicative of existing CPUC policies such as the Renewable Portfolio Standard (RPS), Energy Efficiency (EE), and the carbon adder. It was unclear if the performance standard would substantively change LSE behavior or the LSE emissions footprint, in which case it seems to be an unnecessary program.

Since enrollment of SB1368 many of the parties who had earlier expressed concerns with the concept of an EPS are now focusing their attention on ensuring that the design of an EPS program addresses their substantive concerns and priorities.

B. Implementation/Design

Q3. Assuming that the Commission decides to proceed with an interim EPS, what should be the major design principles/objectives for such a standard?

Most parties agreed with the priorities included in the revised staff proposal, and provided only minor language modifications. Those priorities are:

- 1) Prevent backsliding and commitments that will make future GHG reductions more difficult
- 2) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance⁷
- 3) Reliability:
 - i) short-term: do not force shutdown of essential facilities
 - ii) long-term: consider risks of relying on high emitting resources.
 - iii) Administrative simplicity, regulatory certainty

Other recommendations included specific provisions for LSEs, encouragement of new technologies, incentives to energy efficiency and renewable energy, minimization of gaming, provisions for allowances for cogeneration facilities. Many of these suggestions did not necessarily fit with the “goals” section and were better suited for consideration in timing and implementation of the program.

SF Power also requested that language be included to assure that the interim EPS will not interfere with development of a load-based cap, and that coordination with regional/international groups could occur. The Commission has made it clear that it is committed to implementing a load-based cap in its Order Instituting Rulemaking Decision and throughout this proceeding, and has stated repeatedly that the interim EPS is meant to support such an effort. In addition, the Commission has stated its support for statewide, regional, and international efforts to address climate change. While both of SF

⁷ SB 1368 Section 1(g) states “It is vital to ensure all electricity load-serving entities internalize the significant and underrecognized cost of emissions recognized by the PUC with respect to the investor-owned electric utilities, and to reduce California’s exposure to costs associated with future federal regulation of these emissions.”

Power's recommendations are foundational elements of climate change policies, staff does not view them to be specific design goals of the EPS.

The issue of consistency with statutory guidelines and requirements was also highlighted. This modification has been included in staff's final proposal below.

In addition, staff wishes to highlight Section 8341(d)(1) which provides a broad overview of the purpose and high-level design of an EPS program.

“On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the Energy Commission and the State Air Resources Board, shall establish a GHG performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of GHGs for combined-cycle nature gas baseload generation...”

The revised proposal takes into account parties' recommendations as well as the statutory language in SB 1368, and further recognizes that coordination with the CEC and ARB will also be part of the process of developing and implementing this program.

Q4. Please discuss the relative advantages of the “gateway” approach to an EPS, and the potential disadvantages. If you propose an alternative, please describe.

While not all parties support the concept of an EPS, all parties viewed a gateway screen approach as being the most effective approach if an EPS were to be implemented. No parties proposed an alternative approach to administration of the program.

The principal reasons that parties supported the gateway approach are because it minimizes contract approval uncertainty, sends clear signals regarding compliance, and does not require ongoing administrative oversight and therefore is relatively straightforward to manage. Staff supports a “gateway” standard for these reasons.

Statutory Requirements: The gateway standard proposed by staff and discussed in the workshops is consistent with the language of SB1368, which focuses on LSEs' long-term commitments at the time they are first proposed or entered into:

Section 8341(a) “No load-serving entity or local publicly owned utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment⁸ complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity...”

8341(b)(1) “The commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term

⁸ Section 8340(j) defines long-term commitment as follows: “ ‘Long-term financial commitment’ means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation.”

financial commitment complies with the greenhouse gases emission performance standard established by the commission...”

8341(b)(2) The commission may, in order to enforce the requirements of this section, review any long-term financial commitment proposed to be entered into by an electric service provider, or a community choice aggregator.

Parties provided more detailed recommendations regarding application of a gateway standard and demonstration of compliance. Those recommendations are discussed in more detail in Q18 below.

Q5. The Revised Staff Proposal applies the EPS to new commitments (construction, repowering, and new or renewal contracts). *Please comment on whether you support the Proposal on this issue, indicating your views on the relative advantages and disadvantages of applying the EPS to both new and existing generation facilities (under new commitments). Relate your response to this question to the design priorities you articulate under question #3 above.*

In post-workshop comments submitted prior to enrollment of SB1368, many parties argued that the EPS should apply to new commitments with new facilities only. Others agreed it should apply to “new” facilities but also included repowered facilities as “new” and therefore subject to the EPS. Under this approach, resources currently under contract with an LSE would not be subject to the EPS, even if that contract was to come up for renewal while the EPS is in place. Most of these parties argued that if the CPUC is most concerned with preventing “backsliding” on emissions prior to a cap being implemented, then existing resources should not be subject to the EPS as they are part of the status quo.

A third group of parties argued that all new commitments, including renewal of existing contracts as well as new construction, repowering, and new contracts should be subject to the EPS. Since the EPS is administered on a contract by contract basis using the gateway approach, it is not prudent for the CPUC to “grandfather” in any resources under current contract that would be subject to renewal during the EPS. The Rule should not create an incentive for LSEs to renew existing contracts, rather than making resource decisions based upon the broad portfolio of all available resources. An artificial incentive to renew existing entitlements could arise if the EPS were limited in scope to new resources only.

SB 1368 provides direction as to which resources are to be covered. As indicated above, the definition of “long-term commitment” includes new ownership investment in baseload generation or a new or renewed contract with a term of five years or more. Sections 8341(a) and (b) require that the Commission approve only utility long-term financial commitments that comport with the EPS program and also expressly grants the commission the authority to “review any long-term commitment proposed to be entered into by an energy service provider or community choice provider.

Section 8341(d)(1) also states that "... All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard."

Staff recommends that all new or renewal contracts and/or commitments with resources, including existing, repowered, and new facilities, be subject to the EPS. For the purposes of ensuring that existing contracts and investments are not required to be renegotiated, all facilities that meet the requirements of Section 8341(d)(1) should be deemed in compliance at the onset of the EPS program. As contract renewals and/or repowering of those facilities occur, they should be subject to the gateway standard. The decision to renew a contract or repower generation commits California's LSEs and ratepayers to those costs and emissions profiles just like a decision to enter into a new contract with a new facility.

Q6. Should the EPS cover only commitments (construction or contracts) of five years or longer as the workshop participants generally agreed? *There was also general agreement among workshop participants that if adopted, an interim EPS should cover commitments (construction or contracts) five years or longer, which is also reflected in the Staff Straw Proposal. Do you agree? Why or why not? How does this design parameter achieve (or not achieve) the priorities you have identified under question #3 above?*

All of the parties except for DRA supported the five year or longer commitment cutoff as it comports with the CPUC current long-term procurement plans and with the spirit of the CPUC's Performance Standard Policy Statement.

DRA proposed inclusion of short-term contracts (and contracts smaller than 25MW) as peaking and shaping resources are often higher emitting than baseload resources.

Staff has been directed to recommend an interim program that can be implemented in the near-term. Discussion at the workshop, including that of CPUC staff assigned to procurement activities, and subsequent comment by the majority of parties indicates that inclusion of short-term contracts would be burdensome to manage in the near-term and could raise reliability issues as well. The proposed inclusion of contracts of five years or greater avoids long-term commitments to high-emitting resources, and provides the clearest path to implementation while mitigating reliability issues associated with peak and seasonal demand.

SB 1368 largely lays to rest this debate as Section 8340(j) provides the definition as follows: "'Long-term financial commitment' means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."

Based upon the statute, and consistent with the majority of parties' views, staff continues to recommend that the EPS cover commitments (construction or contracts) of five years or longer.

Q7. Another major design issue discussed at workshops was what the Commission should look at (contract or facility operation) in determining whether the EPS applies. In particular, should the Commission (1) look at the operation of the facility underlying a contract, or (2) only to the amount/product contracted for by the LSE? The Staff Proposal takes the approach that, for specified contracts, the Commission should look at the expected operation and emissions of the facility, rather than just the contracted amount. Please comment on the advantages and disadvantages of these two alternative approaches, and your position on this issue.

Specified Commitments:

For specified contracts and commitments, several arguments emerged. PG&E argued that the screen should be applied to the resources procured under the contracts and not the entire facility or facilities that happen to be owned by the contracting party.

SDG&E/SoCalGas, SCE, and Constellation further argued that it would be burdensome to identify the operations of the underlying resource.

Alternatively, other parties supported inclusion of facility operations as part of the gateway review. PacifiCorp and IEPA recommended that the facility's average emission rate be used as the appropriate emissions factor in the case of specified contracts.

Calpine, DRA, NRDC/TURN/UCS supported review of the underlying facility as well.

DRA and GPI also recommended that the definition of baseload generation be modified to include powerplants operating at a capacity factor of 50% or greater.

The revised staff proposal recommended that specified long-term contracts and commitments of 25MW or greater delivered to the grid with a capacity factor of 60% or greater be required to go through the gateway screen. At that point, the emissions factor for the underlying facilities would be applied.

SB1368 offers guidance on the definitions of baseload generation, long-term financial commitment, and capacity factors.

Section 8340(a) specifies that "‘Baseload generation’ means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent."

Section 8340(j): "‘Long-term financial commitment’ means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."

Section 8341(b)(4) states, “In determining whether a long-term financial commitment is for baseload generation, the commission shall consider the design of the powerplant and the intended use of the powerplant, as determined by the commission based upon the electricity purchase contract, any certification received from the Energy Commission, any other permit or certificate necessary for the operation of the powerplant, including a certificate of public convenience and necessity, any procurement approval decision for the load-serving entity, and any other matter the commission determines is relevant under the circumstances.”

Regarding the overall purpose of an EPS, Section 8341(d) states, “On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the energy Commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation.

The statutory language is prescriptive in its preference for an annualized capacity factor of 60 percent or greater, and does not provide provisions to reduce the percentage that is used in defining baseload generation.

The language does offer flexibility regarding the methods and documentation used to determine in calculating the capacity factor for the commitment. Parties have identified two primary options in determining the capacity factor attributable to an LSE’s commitment: 1) evaluate the commitment based upon the LSE’s intended use of the powerplant, or 2) evaluate the commitment based upon the design and intended use of the underlying powerplant itself.

The overall purpose of the EPS is encapsulated in Section(d)(1) with the commission being required to “establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities.”

Based upon discussion at the workshop, comments submitted by parties, and the provisions of SB 1368, staff recommends that in the case of contracts, or other commitments with specified facilities, the annualized capacity factor of the underlying resource, rather than the size of the LSE commitment, should be used in determining whether the gateway screen applies. SB 1368 is clear in establishing its interest in ensuring that LSEs do not enter into contracts with baseload facilities whose emissions are higher than combined cycle natural gas powerplants designed and intended for baseload operations.

NRDC/TURN/UCS/WRA presented persuasive arguments regarding the intent of the legislation in providing their arguments in support of underlying resource review. For specified contracts, the capacity factor, average heat rate, and emissions factor of the underlying facility(s) supplying power should be readily available as operators are

required to provide this information to multiple regulatory agencies such as the US EPA and CA Air Districts.

Constellation and EPUC/CAC express concern that under the revised staff proposal Utility Retained Generation (URGs) would not be subject to the EPS. PG&E argues that only changes to a powerplant that result in a net increase of the rated capacity of the plant be considered as changing the status of the facility from being deemed in compliance to being required to demonstrate compliance. NRDC/TURN/UCS/WRA recommend that URGs that undergo major renovations be covered under the cap.

Staff accepts NRDC/TURN/UCS/WRA's proposal on this point. Major renovations of existing facilities, like other major financial commitments, involve long-term commitments that will affect power costs, environmental impacts, and ratepayer interests for many years. As the nation has learned with respect to "new source" standards under the Clean Air Act, extensive renovation does not necessarily require expansion, but it does implicate long-term emissions trends. Including such events in the definition of long-term commitments is reasonable and comports with the definition of baseload generation as defined in Section 8340(a).

Based upon discussion at the workshop and post-workshop comments filed, staff recommends that the underlying resource's annualized operations and emissions profile be used in determining whether the gateway screen is triggered. For specified contracts, the capacity factor, average heat rate, and emissions factor of the underlying facility(s) supplying power should be readily available as operators are required to provide this information to multiple regulatory agencies such as the US EPA and CA Air Districts.

Unspecified contracts:

For unspecified contracts, the IOUs argue that the requirement to include information about an underlying facility's operation would be administratively burdensome, and in many cases impossible, as the facility or facilities under contract would either not be known or facility operations would be proprietary information and not likely to be disclosed to a contracting LSE. LS Power and Constellation believe that only new resources should be included in the EPS in order to simplify the reporting process.

PacifiCorp argues that unspecified contracts should be required to have an emissions rate imputed on a MWh basis. Other parties (NRDC/TURN/UCS/WRA, DRA) support looking at the underlying resource in order to ensure that LSEs are not entering small contracts with large high emitting baseload resources, and to limit gaming of the system based upon size of contract.

Based upon parties' comments, it is evident that it would be burdensome and in many cases infeasible to estimate the operations of unspecified facilities. The staff proposal recommends review of unspecified contracts based upon the size of the commitment, rather than the specific emissions profile of the underlying facility as it is understood to be unknown. In cases where it is known that the underlying facility's capacity factor is less than 60%, the gateway screen would not apply. If the capacity factor is either

unknown, or known to be 60% or greater, the gateway screen would apply. For unspecified contracts, an appropriate emissions factor would be imputed, from the best available information, as discussed at Q 15 below.

However, staff does recognize the potential gaming issues raised by DRA and NRDC/TURN/UCS/WRA and makes the following recommendation under “All commitments” below to address potential “slicing and dicing” of contracts, or other evasive procurement activities that may be undertaken to avoid an EPS screen. In addition, to the extent possible, staff encourages LSEs to enter into specified contracts.

On the subject of treatment of unspecified power, SB 1368 offers the following in Section 8341(d)(7): “In developing and implementing the greenhouse gases emission performance standard, the commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.”

All commitments (specified and unspecified):

The focus of the interim EPS program is on power supply reliance and financial commitments by California LSEs for baseload resources. By limiting inclusion of covered resources to LSE commitments of 25MW or greater, staff intends to reduce the administrative burden of compliance with an EPS, and to focus attention on LSE’s long-term baseload commitments rather than peaking or shaping activities required for reliability. Thus, we recommend that the 25 MW threshold apply to the contract or other commitment made by a LSE.

At the same time, the Rule should not create incentives for LSEs to avoid the substantive standard simply through contractual “gaming” – that is, by entering into multiple smaller contracts, each of which may be below the jurisdictional thresholds, but which together amount to a significant long-term commitment of LSE resources. To that end, staff recommends that a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources should be considered as a single commitment in size, capacity factor, and duration.⁹

Such multiple contract activities must be disclosed by the utilities to the CPUC in order to avoid “slicing and dicing” of large contracts to avoid or manipulate the gateway screening process for the performance standard review. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement mechanisms.

NRDC/TURN/UCS/WRA raise concerns about this approach to ensure contract gaming does not occur. They are specifically concerned that it is administratively burdensome. Instead they recommend that all LSE contracts of 5 MW that have an underlying resource

⁹ Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

operating at an annualized capacity factor of 60 percent or greater be covered by the gateway screen. By using this approach, after the fact review regarding contract gaming via “slicing and dicing” would not be necessary.

Staff sees the merit in this approach, but does not view it to be reasonable given the implementation timeframe for the program and the upfront administrative burden that would be required for compliance. Rather, staff is inclined to focus on larger contracts as consistent with current long-term procurement processes and data available, and to make further modifications and improvements to the program as the program matures as consistent with Section 8341(b)(3), “The commission shall adopt rules to enforce the requirements of this section, for load-serving entities. The commission shall adopt procedures, for all load-serving entities to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the greenhouse gases emission performance standard to ensure compliance with the standard.”

We recognize that some professional judgment is required to determine when certain contractual commitments are “related” or “similar” so as to trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

Q8. There was general agreement during the workshop that an interim EPS should not apply to peaking facilities or resources expected to operate relatively few hours during the year. Accordingly, the Staff Straw Proposal uses a definition for “covered resources” as those with an annual average capacity factor of 60% or greater, intending to cover resources operating as year-round base load and high-use intermediate and shaping facilities. Do you believe that this definition of covered resources is appropriate? In responding, please address the following:

a. What types of resources do you believe the EPS should cover and whether you believe the straw proposal capacity factor (60% or greater) metric to define a covered resource will capture those resources.

Most parties recommended that the EPS cover all baseload resources defined as those resources with a 60% or greater capacity factor (c.f.). Parties that supported a 60% c.f. referenced data submitted by the IOUs in responses to data questions 1 and 2 (“Size of potential IOU procurement needs that would be covered by an EPS” and “Portion of GHG emissions from long-term commitments that would be included at various capacity factors”). Data submitted for questions 1 and 2 illustrated that a 60% c.f. captures 78% of the IOUs’ 2012 open procurement need and would capture 72% of CO2 emissions.

Lowering the threshold capacity factor to 40-50%, (as suggested by GPI and DRA) would result in additional emissions captured, but these reductions would not be as

significant as the incremental step-down from 70% c.f. to 60% c.f., which represents the largest delta with regards to emissions reductions at the different capacity factors. For example, a 50% capacity factor would affect an additional 5% of procurement and capture an additional 6% of CO₂ emissions. Comparatively, the move from 70% c.f. to 60% c.f. affects an additional 13% of procurement and captures 13% more emissions.

Based on the data and comments, staff recommends a 60% capacity factor as a reasonable threshold and one that comports with the requirements of Section 8340(a). This approach captures the large majority of emissions from potentially emitting resources, while minimizing administrative burdens and potential interference with resources needed to meet peak loads.

b. Present an alternative metric(s) for defining “covered resources” that you recommend, if you do not support the Staff Straw Proposal definition.

GPI and DRA advocated for a lower than 60% capacity factor (40%-50%) to ensure that all high emitting intermediate and shaping facilities are covered.

See discussion and staff recommendation above (Q8.a.)

c. Whether (and if so, how) the EPS should incorporate a research and development exemption for advanced coal or other technologies.

Some parties suggested an R&D exemption for advanced coal technologies and specifically one for IGCC carbon capture-ready technology (SCE, PacifiCorp). SDG&E suggested a more general, non-technology specific R&D exemption that could be applied on a case-by-case basis. Other parties argued that no exemptions should be granted and that all resources should be required to meet the EPS (Calpine, DRA, NRDC, TURN, UCS, GPI).

Based on parties’ comments, staff recommends a R&D exemption that could be granted by the CPUC on a case-by-case basis for higher-emitting facilities upon demonstration that the commitment in question will make a significant contribution to developing a lower-emitting resource mix in the future. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions, and that has or will have within a reasonable period of time the capacity and an existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement.

In addition, in the case of powerplants that have implemented geologic carbon sequestration technology, staff recommends that the sequestered CO₂ be excluded from the emissions calculation for that facility as consistent with Section 8341(d)(5):

“Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard.”

Q9. Another design issue discussed at the workshop was how the EPS should apply to specified contracts with more than one underlying covered resource (new or existing): Should the Commission apply the EPS to the “blend” of the resources/units, or require that each covered resource meet the EPS individually?

Under the Staff Revised Proposal, each individual covered resource must meet the EPS, with the exception of a renewable contract firmed with a non-renewable resource. In that case, the blend of the two must meet the EPS, rather than the individual resources/units.

Do you agree with this approach? Why or why not? In your response, present your view of the relative advantages and disadvantages of the alternate approaches, and discuss your recommendation in the context of your answer on design priorities under Question #3.

Many parties supported the staff proposal recommendation. However, a language nuance was raised by several parties. The staff proposal requires each covered resource to be in compliance with an EPS. Parties communicated difficulty in determining the activities of specific units that may be operating at a multi-unit facility or plant. SDG&E suggests in these cases to use the information available at the plant level, and to allow for exceptions where necessary.

Regarding renewable power firmed with a non-renewable resource, PG&E felt strongly that any RPS eligible resource, regardless of any associated firming resources, should be deemed in compliance with the EPS.

GPI recommended clarification language regarding determination of the capacity factor for renewables firmed with fossil resources. They suggest that the combined annual capacity factor of the resources be used in determining whether the screen applies or not. Staff supports this recommendation.

For contracts with multi-unit powerplants where contracts where specific unit operations are unknown, staff recommends modifying the proposal to allow for facility/plant average as SDG&E suggests. In the case of renewables with covered firming resources, staff recommends no change to the revised proposal-- the resource blend must meet the EPS. Staff recognizes that the California Energy Commission (CEC) sets eligibility rules for generation resources that can counted toward the Renewables Portfolio Standard (RPS). Pursuant to SB 107 (Simitian), CEC must develop criteria for RPS eligibility of shaped and firmed renewable generation. Staff recommends that this Commission continue to coordinate with the CEC to ensure consistency in these matters.

Q10. In the context of the Staff Revised Proposal, how should the Commission treat partial contracts under the proposed EPS? An example discussed at the workshop was a “summer product” contract for power from a specified coal plant. For partial contracts, should the Commission look at how the facility is operating during the duration of the contract commitment, at the MWhs being purchased relative to the full year of facility operations, or consider other approaches? Would your proposed

treatment of partial contracts result in an exemption under the 60% capacity factor rule, even if that underlying facility would be a “covered resource” under average annual operation? Why or why not?

Most parties recommend that, similar to Q7, the contract be subject to the EPS rather than the underlying facility. Many parties expressed concern about inclusion of short-term shaping resources in the EPS, as these resources are required for seasonal reliability and are not baseload resources.

NRDC/TURN/UCS supports inclusion of these contracts on the basis of the underlying resource.

Staff recommends that partial-year contracts for shaping resources that have less than a 60% annualized capacity factor not be covered by the EPS because of the seasonal reliability issues that they address. It is important to note that this distinction is based upon the size and expected capacity factor of the commitment (and thus its GHG emissions), not its name or degree of dispatchability.¹⁰ However, the multiple contract provisions discussed above in Q7 would apply. LSEs are not allowed to enter into multiple small or shaping contracts in order to avoid the EPS gateway screen.

Q11. The Staff Straw Proposal allows for an exemption from the standard for specified units of 25 MW or smaller, based on the size of the facility under construction or providing power under a contract. However, there would be no size exemption for unspecified contracts of any size. In commenting on this aspect of the Straw Proposal, please address the following:

- a) The MW level of the “small unit” exemption under this proposal. Do you support this exemption as proposed? Would you propose a different size exemption level and/or one specifically tied to projects qualifying under the self-generation incentives program? No exemption? Why or why not?**

The majority of parties supported inclusion of resources 25MW and greater for specified units, on the basis of current long-term contract requirements, compatibility with the Air Districts and US EPA regulations, and because it comports with the Northeastern Regional Greenhouse Gas Initiative (RGGI) emissions cap program.

In addition, many parties argued that all contracts, including unspecified, be subject to the 25MW or greater threshold in order to maintain consistency and to minimize administrative complexity (PG&E, SCE, SDG&E, IEPAA, CCC, EPAC, CAC).

NRDC/TURN/UCS, DRA, and in some cases GPI, support a 5MW cutoff for compatibility with the self-generation incentive program (SGIP), and to ensure inclusion of high emitting resources associated with small contracts. Further NRDC/TURN/UCS

¹⁰ Thus, acquiring a resource for “shaping” purposes, or because it can follow load does not for these reasons alone exempt it from application of the gateway criteria recommended in this Report.

suggests that no size exemption be given for unspecified contracts since it is impossible to identify the resources behind these contracts.

Staff recommends no change to the current proposal for specified contracts, as it is not persuaded that significant benefits would result from lowering the size threshold for review.

For unspecified contracts, staff recommends a 25MW or greater threshold for contracts and commitments for the screening process in order to focus on long-term contracts, create consistency, and mitigate administrative complexity across the screening process. Parties did not present persuasive arguments to support a requirement that all unspecified contracts should go through the screening process.

The interim EPS is meant to be implemented in the near-term and mitigate administrative complexity where possible. Being that the program is intended to focus on long-term baseload contracts, and we are adding provisions for multiple contracts to prevent “slicing and dicing” of contracts, staff recommends that 25MW be the cutoff for both specified and unspecified commitments as it is most consistent with current Commission, state, and other jurisdiction’s emissions policies.

- b) Basing the exemption on MWs delivered to the grid. In determining eligibility for the size exemption, the Staff Revised Proposal would subtract out self-generated power that was not delivered to the grid.**
 - i) Please indicate whether you agree with this approach to determining the size exemption, why or why not?**
 - ii) If the Commission adopts this approach, what type of information (and source of data) would need to be presented for the Commission to determine the amount of expected self-generation to subtract from the unit size?**

The majority of parties commenting on this matter support the staff proposal, and the calculation proposed for crediting cogeneration facilities.

NRDC/TURN/UCS/WRA suggest that the EPS apply to all of the emissions associated with a LSE’s contracts, even if the energy is used on-site as GHGs are emitted either way. However, where the electrical output retained on-site by a customer is not part of the LSE’s financial commitment or acquisition, we cannot conclude that it falls within either the commission’s purposes in establishing the EPS, or the definition of covered resources in AB 1368. Thus, the Revised Staff Proposal continues to focus on the size of the resources delivered to the grid or otherwise made a part of the LSE’s portfolio.

With respect to the calculation of emission rates at co-generation facilities, Staff recommends adoption of the methodology proposed by EPUC/CAC. This method is consistent with Section 8341(d)(3), which requires the commission to establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all

greenhouse gases emitted by the facility in the production of both electrical and thermal energy.

Staff recommends use of the cogeneration "methodology" put forward by EPUC/CAC and supported by CCC as an interim recommendation for the purpose of meeting the implementation deadline of February 1, 2007 as required in Section 8341(d)(1) and compliance with Section(d)(3). This calculation could be modified in the future if the Commission deems it necessary. Staff also notes that for the purposes of consistency, all electricity delivered to the grid by a cogeneration facility is subject to the gateway screen as with other specified resources delivering electricity to the grid. During the "gateway screening process" this methodology still requires a case by case evaluation, because the data used to make the calculation will be different for every plant.

Section 8341(d)(3) states "The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy.

- c) Basing the exemption on the size of the unit being constructed or underlying a unit-specified contract, rather than the size of the contract. Please discuss the relative advantages and disadvantages of these alternate approaches to a size exemption, and indicate which you would recommend, should the Commission determine that a size exemption would be appropriate. (You may refer to your answer to the related Question 7, as appropriate).**

As discussed in Q7 and Q11a, after review of the comments, staff recommends that specified long-term contracts and commitments of 25MW or greater delivered to the grid be required to go through the gateway screen. The screen would apply to the committed underlying resource and its average emissions factor. For unspecified contracts, staff recommends the emissions factor for unspecified contracts be imputed based upon the contract size rather than attempting to identify the emission rates of the underlying facility or facilities. We realize that a more detailed emissions tracking system will be of great use to LSEs in the context of a load-based cap-and-trade system, but are persuaded that individual facility emissions rates may not be readily available to LSEs for unspecified contracts at this time.

For specified contracts, DRA and NRDC/TURN/UCS arguments to lower the size threshold did not substantiate the benefits to doing so. The vast majority of commenting parties supported the 25MW or greater threshold as it comports with current CPUC, state, federal, and regional emissions policies, and comports with the interim EPS focus on baseload resources.

For unspecified contracts, parties persuasively argued that information about underlying resources would be difficult, if not impossible, to ascertain at the present time. Because

of this administrative impediment, staff recommended in Q7 to modify the unspecified rule to trigger the gateway screen.

d) No size exemption for any unspecified contracts. Do you support this approach? Why or why not?

Most parties did not comment on this issue. SCE recommends the same size exemption for specified and unspecified contracts¹¹. LS Power believes that it is unlikely that new non-unit specific contracts will be entered into during the period of the interim EPS, so views this as a non-issue. IEPA believes that no exemptions should be made for unspecified contracts. NRDC/TURN/UCS supports the staff proposal recommendation to require all long-term unspecified contracts of any size to be covered by the EPS.

For the reasons discussed above (see discussion at Q7), staff recommends that the EPS apply to the size of the commitment involved rather than to the size of the underlying facility or facilities that may be supporting the contract. We recommend setting the size exemption for unspecified contracts at the same level as for commitments with specified facilities (i.e. 25MWs or greater). If the EPS is designed to look at the emissions associated with a contract or commitment, then it is reasonable, and easier to administer, if the size of contract covered under the EPS is the same for both specified and unspecified resources. Provisions to aggregate multiple contracts will be needed in order to avoid contract gaming for jurisdictional purposes (see discussion at Q7).

Q12. Under the Initial Staff Straw Proposal, the Commission would develop two separate standards for covered resources: 1) a “moderate” EPS to apply to existing resources and repowering and 2) a “high” EPS to apply to new resources. Both would be based on the performance of a combined-cycle gas turbine (CCGT).

Please address the following questions in your comments on this approach:

- a. Do you agree in concept with a dual standard as outlined in the Staff Straw Proposal, why or why not?*
- b. If the Commission adopted this approach, what performance standard do you recommend for the “moderate” and “high” EPS? Express your answer in terms of heat rates as a proxy for GHG emission rates. Explain why you chose these levels, and the source of data/calculations you used to develop them.*
- c. If instead you recommend a single EPS based on the performance of a CCGT for all new commitments (whether to new resources, existing or repowered facilities), provide your recommended performance standard (expressed as a heat rate), explain why you chose this level, and the source of data/calculations you used to develop it.*

¹¹ “Specified contracts” are contracts that specify the generating units or facility providing the power, while “unspecified contracts” are not linked to any particular generating resource.

d. In responding to b. and c. above, be specific as to how you developed your CCGT reference standard and the data sources/calculations used. For example, did you base it on the expected performance of a modern CCGT newly placed in service, or at the end of its useful life, or an average of emissions from existing CCGTs, or another approach?

e. If you have alternate or additional recommendations for the EPS standard and calculation, please submit them.

Data submitted by a working group composed of the IOUs and other parties in response to data question 3: “What are the representative heat rates/emission rates for different types of facilities?” provided the background for parties’ responses to Q12. The first worksheet, “Heat rate and emissions w/vintages,” shows that emissions for those CCGT plants built from 1980 to present range from 800-1020 lbs CO₂ / MWh. Within this range, there are no significant difference among vintages. In contrast, for other types of gas plants, such as single turbine, the range extends upwards to 1250 lbs CO₂/MWh.

Since both existing and new CCGTs perform at nearly the same levels, and since there are strong economic incentives for new gas facilities to perform efficiently, staff concludes that it is not necessary to impose a stringent standard for “new” facilities as opposed to existing units. New or repowered CCGT plants are likely to have a low emissions profile in order to be competitive. Most parties suggested one EPS standard instead of a moderate and high standard. Two reasons were given: administrative ease (LS Power, Constellation) and the ability of one standard to sufficiently incorporate all existing CCGT plants while discouraging less clean facilities (NRDC/TURN/UCS).

Based upon comments and the data presented, staff does not see the need for two EPS standards.

The second worksheet, “Spreadsheet of existing emissions rates” provides emissions data from EPA’s Continuous Emissions Monitoring System (CEMS) on existing CA gas plants. This spreadsheet details that the range of emissions from CA gas plants operating at 60% capacity factor or greater is between 794 and 1,006 lbs CO₂/MWh with an average of 856 lbs CO₂/MWh.

Multiple parties proposed 1,100 lbs CO₂/MWh as the single standard (SDG&E, NRDC/TURN/UCS, GPI). SCE proposed a high standard of 1,000 lbs CO₂/MWh and a moderate standard of 1,400 lbs CO₂/MWh.

After consideration of the data and suggestions proposed by parties, in the Revised Staff Report, staff recommended a single standard, applicable to new and existing plants and contracts, of 1,000 lbs CO₂/MWh. This standard allows for high performing existing CCGTs to qualify and is significantly above the average emissions reported for gas plants within and outside of the state.

The majority of parties commenting on the Revised Staff Report's recommendation of 1,000 lbs CO₂/MWh were opposed (PG&E, SDG&E/SoCalGas, SCE, GPI). Most of these parties recommended a value of 1,100 lbs CO₂/MWh as being most reflective and inclusive of the current CCGT fleet and consistent with Section 8341(d)(1) which requires the emissions performance standard "to be no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation."

Some parties (NRDC/TURN/UCS/WRA, Calpine, and DRA) supported setting the standard at 1000 lbs CO₂/MWh as it would encourage operations of, and investments in , the cleanest CCGT facilities and technologies.

One party, SF Community Power, argued for a standard that would focus on coal resources specifically and suggested that the Commission should not approve procurement from a coal plant with average net emissions greater than a supercritical steam turbine coal-fired plant, or based upon a MWh emissions rate from an inefficient California-based gas-fired steam plant.

Staff rejects SF Community Power's arguments as we view them to be in conflict with Commission's GHG Policy Statement and with SB1368. In the October 6, 2005 GHG Policy Statement, the Commission describes a GHG emissions performance standard that would limit the GHG emissions levels for all new utility-owned generation and all long-term procurement contracts to "no higher than the GHG emissions levels of a combined-cycle natural gas turbine." Staff does not see the merits of expressly excluding a resource based upon fuel type or geographic location. The EPS as currently contemplated is anticipated to include all new and renewed LSE sources and contracts for power subject to the gateway standard regardless of resource type or location.

Further, staff does not believe this recommendation comports with Section 8341(d).

Based upon parties' comments on the Draft Staff Workshop Report and in light of the passage of SB 1368, staff recommends modifying the acceptable emissions rate for the single standard to be 1100 lbs CO₂/MWh.

In addition, staff reiterates the recommendation regarding Q5 above: Staff recommends that all new or renewal contracts and/or commitments with resources, including existing, repowered, and new facilities, be subject to the EPS. For the purposes of ensuring that existing contracts and investments are not required to be renegotiated, all facilities that meet the requirements of Section 8341(d)(1) should be deemed in compliance at the onset of the EPS program. As contract renewals and/or repowering of those facilities occur, they should be subject to the gateway standard. The decision to renew a contract or repower generation commits California's LSEs and ratepayers to those costs and emissions profiles just as a decision to enter into a new contract with a new facility.

Q13. There was general agreement at the workshop that the Commission should allow credit for cogeneration thermal load when applying the EPS to covered resources. This is reflected in the Staff Straw Proposal. Do you agree with this approach, why or why not?

If you have developed a specific formula for the calculation of such a credit, please provide it in an attachment to your post-workshop comments, or in a separate joint submittal at the same time (if you are joining in with other parties on this issue). Indicate whether it is consistent with methods used to credit thermal loads in other emissions regulations for cogeneration facilities, either in California or elsewhere.

As part of the post-workshop data requests, EPUC/CAC submitted the following formula¹² for calculation of a revised emissions rate for cogen facilities that reflects credit for useful thermal energy: $\text{Emission Rate} = \text{Total GHG Emissions} / \text{kWh of Electricity} + \text{Btu Thermal Energy (converted to kWh)}$. This calculation was also supported by CCC and DRA.

Concerns were expressed by some parties that the above calculation overstates useful thermal energy. Alternatives to the calculation include:

1. Apply a discount factor such as 50% to the formula to correct for the assumption that all thermal energy is convertible to electricity (SCE);
2. On a case-by-case basis, assume thermal application separate from electricity production by calculating CO₂ savings from avoided boiler use (assuming 80% boiler efficiency) and subtracting saved lbs CO₂ / kWh from standard facility lbs CO₂ / kWh.
3. Although not providing a specific alternative, NRDC/TURN/UCS advocated for a methodology to be applied on a case-by-case basis that accounts for useful, and not only theoretical thermal energy.

Staff recommends the cogeneration methodology put forward by EPUC/CAC and supported by CCC as an interim recommendation for the purpose of meeting the implementation deadline of February 1, 2007 as required in Section 8341(d)(1). This calculation could be modified in the future if the Commission deems it necessary. During the "gateway screening process" this methodology still requires a case by case evaluation, because the data used to make the calculation will be different for every plant.

Q14. Do you have a position on how to calculate the net emission rates from renewables (e.g., for waste-to-energy, geothermal resources) for the purpose of applying the EPS? If so, please present your views either in your individual post-workshop comments or jointly with other interested parties at the same time.

Most parties commenting suggested assigning a zero emissions rates for all renewables, including those from biogenic sources (PGE, SDG&E, DRA, GPI, IEPA). NRDC/TURN/UCS/WRA suggested net emissions be considered for biogenics and zero emissions rate for other renewables, and also recommended that the Report clarify that

¹² Their presentation at the workshop providing background for this recommendation is posted at www.cpuc.ca.gov/static/energy/electric/climate+change/cogen+calculationpresentation.pps

commitments for renewable resources be required to go to the gateway and not be deemed exempt resources.

The rationale provided by GPI in its recommendation for assignment of zero emissions to all renewables including biogenics, is that although biogenic renewables (biomass and biogas generators) have higher GHG emissions from the stack than CCGT, when net emissions are properly accounted for, these resources reduce the net emissions associated with the alternative disposal of these same materials and eventually have lower emissions than CCGT plants.

Section 8341(d)(4) states, “In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the commission shall consider net emissions from the process of growing, processing, and generating the electricity from the fuel source.”

Based on parties’ comments and the statutory language above, staff recommends that long-term baseload contracts and commitments with renewable resources be covered by the EPS. As any resource, these commitments should appear at the gate and file their applicable net emissions rate. Resources identified in Section 8341(d)(4) shall include their emissions estimates in manner compliant with that section. Staff supports NRDC/TURN/UCS/WRA’s clarification that baseload commitments for renewable resources are not exempt from the EPS.

Q15. There was discussion during the workshop on how to address unspecified contracts, i.e., what imputed emissions factor to use. The following alternatives were identified:

- a. *Western Energy Coordinating Council (WECC) system average;*
- b. *Appropriate geographic average (e.g., Northwest purchases represent different resources than purchases from the Southwest);*
- c. *California Energy Commission (CEC) “Net System Power” calculations;*
- d. *Default to coal emission rates.*

Please discuss your recommended approach, and why. Be as specific as possible as to the source of the data (or specific numbers) you would use for this purpose.

The CEC provided data on the underlying fuel mix for imputation factors(a)-(c) above. Emissions rates for (d). (coal) were provided as part of the emissions data in data question 3. Although imputed emissions rates were not provided for these options per se, the provision of the underlying fuel mix sheds sufficient light on whether such an emissions rate would pass a CCGT-based EPS.

Parties had varying opinions on the appropriate imputed emissions factor. PG&E advocated for a geographic average that would distinguish among WECC sub-regions. SDG&E, PacifiCorp, and IEPA suggested use of the CEC Net System Power calculation.

NRDC /TURN/UCS recommended assignment of a coal emissions factor in order to deter LSEs and suppliers from reclassifying coal contracts as unspecified power. DRA also suggested that unspecified power should not be considered as meeting the EPS.

Sempra suggested modifying WREGIS, or some other tracking system, to track emissions from contracts. While this suggestion has significant merit in the longer term, for the purposes of implementing a program by the February 1, 2007 deadline, it is not currently feasible as no tracking system, including WREGIS, is available or being developed that could manage the tracking of emissions from unspecified contracts.

Other parties disagreed with the use of any imputed emissions factor since it is:

1) unlikely unspecified contracts will make up a significant portion of long-term contracts anyway (Constellation), 2) an imputed factor automatically sets up an unproductive binary scheme in which all or none of the resources pass (SCE), or 3) the use of proxies for emissions do not reflect the actual emissions from a resource and therefore all power should be specified (Calpine).

Staff recognizes the imperfect nature of the use of emissions factors. However, for the purposes of implementing an EPS program in the near-term, staff acknowledges the need to determine how unspecified power commitments will be treated. In the near-term, there is no tracking system available to accurately collect emissions information to determine the exact nature of the facilities that lie behind unspecified power deliveries. Staff is not persuaded that unspecified resources should thus be disallowed altogether.

Generally, the Commission is given broad authority to address enforcement and verification of compliance with the program.

Section 8341(b)(3) “The commission shall adopt rules to enforce the requirements of this section, for load-serving entities. The commission shall adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the green house gases emission performance standard to ensure compliance with the standard.”

In looking at alternatives (a)-(d) above, staff characterizes them as following:

- a) WECC system average: Incorporates all generation activities throughout the western region.
- b) WECC geographic average: Computes an emissions factor for all generation activities in various regions of the WECC system such as the NW, SW, etc.
- c) CEC calculated “ CA Net System Power Average”: This average accounts for and weights by region the differing emissions factors from unclaimed resources generated in CA and imported to CA.
- d) Coal emissions factor: would be based upon representative emissions from coal generation.

Based upon review of the data and parties comments, staff finds that the WECC system average is generally not reflective of CA activities or market. Using this average would be somewhat arbitrary as staff does not believe that it is specific enough to load served in CA.

Similarly, the WECC sub-regional geographic averages suffer from the same shortfalls and broad sweeps, and would further penalize and reward LSEs differently based upon the major geographic source of their imported system power, which is largely a function of the location of their service territory within California. While we recognize that a different approach may be necessary for the cap-and-trade program, staff is uncomfortable making a geographic assignment that would set up different regional emissions factors for the purpose of the Phase 1 EPS program.

Regarding the use of coal as a proxy emissions factor, staff does not view this as a reasonable approach. While it is simple to administer, it is not an accurate reflection of the characteristics of all unspecified resources.

Staff acknowledges the concern raised by some parties that LSEs will be inclined to enter into unspecified contracts with high emitting resources in order to circumvent the EPS by having a possible lower emissions rate assigned to that resource. Based upon the comments, especially the assertion that long-term contracts with unspecified resources are a small fraction of the incremental power supply, staff does not anticipate this being a substantial issue. Staff will monitor contracting patterns and behaviors to ensure they do not change for this reason. In addition, staff also has recommended provisions for multiple contracts (see Q7.) to avoid “slicing and dicing” of larger contracts.

The CEC’s CA Net System Power Average is currently used by the IOUs for power content labeling purposes. The Average takes into account the geographic origins (in-state and imported) of all of the State’s unclaimed power sources, and assigns weights to the relevant emissions factors to create a single factor, that can be applied equally across all CA LSEs. Of the options, this Average and its imputed emission factor is the most representative of CA’s unclaimed energy mix. Staff views this to be the superior of the options and recommend its use as it is the most comprehensive and accurate of the options. Staff notes that the CEC is currently refining the methodology for the net system power mix and expects to have an updated version this fall. Staff recognizes that the CEC periodically updates its Net System Power Average and methodology. Therefore, staff recommends that throughout the life of the EPS program, the most recently adopted CEC Net System Power Average be used at the time of evaluation of new or renewed commitments.

Q16. The Staff Revised Proposal does not include offsets or market price safety valves under the interim EPS, but does provide for a case-by-case reliability “safety valve” review by the Commission. *Please comment on this aspect of the proposal, and provide your recommendations.*

In their responses to this question, parties presented a number of scenarios that might trigger a “safety valve” response or an exemption such as:

- ability to meet reliability standards established by CAISO, unless they can be met while also meeting the EPS (PG&E, Constellation).
- any unforeseen circumstances (SDG&E and SoCalGas)
- investment in advanced coal technologies to support the Western Governor’s Conference recommendations (SDG&E and SoCalGas)
- cost issues that could trigger an “economic safety valve” (SCE)
- Statutory language allowing the Governor to make modifications to GHG programs in event of extraordinary circumstances, catastrophic events, or threat of significant economic harm- Health and Safety Code Section 38599(a). (Semptra)
- Jurisdictional issues (PacifiCorp)

In addition, several respondents commented on the use of offsets in the EPS program. LS Power and EPUC/CAC generally support offsets as part of an EPS program. Others recommended coupling offsets with a “safety valve” (Constellation).

Most parties did not support the inclusion of offsets at this time. Calpine viewed them as not fitting with the concept of an EPS program and anticipated unnecessary delays in implementation if offsets were to be included. Constellation and IEPA also did not see this fitting with an interim EPS, and stated that they might be more applicable to a cap program. NRDC/TURN/UCS generally do not support the use of offsets and safety valves with the program.

In the draft proposal, exemptions can be made based upon reliability at the discretion of the Commission. In order to implement an interim program in the near-term, we recommend not including provisions for a safety valve or offsets as part of the initial program as both of these issues would require significant up front analysis and ongoing monitoring. These issues are best addressed as part of Phase 2 of this proceeding focusing on design and implementation of a load based cap.

However, staff recognizes provisions for cost and reliability included in SB 1368 in the following sections:

Section 1(g) “It is vital to ensure all electricity load-serving entities internalize the significant and underrecognized cost of emissions recognized by the PUC with respect to the investor-owned electric utilities, and to reduce California’s exposure to costs associated with future federal regulation of these emissions.”

Section 8341(d)(6) “In adopting and implementing the greenhouse gases emission performance standard, the commission, in consultation with the Independent System Operator shall consider the effects of the standard on system reliability and overall costs to electricity customers.”

Staff modifies its proposal to allow for reliability and cost based exemptions on a case-by-case basis at the discretion of the Commission. Staff recommends no change to the previous proposal regarding offsets or explicit safety valves.

Q17. From a policy perspective, please discuss whether energy service providers, qualifying facilities (QFs) and other jurisdictional load-serving entities (LSEs), including multi-jurisdictional utilities, should be subject to an interim EPS along with PG&E, SCE and SDG&E, should the Commission decide to adopt one. Limit your comments to policy considerations, rather than legal argument.

If you have considered the issue of how the Commission would apply an interim EPS to multi-jurisdictional utilities, please present a protocol for allocating emissions among resources serving multiple states with your post-workshop comments.

Many respondents to the initial proposal, including all three IOUs, GPI, NRDC/TURN/UCS, IEPA, argued that all CPUC jurisdictional LSEs should be included in order to ensure uniformity, consistency and mitigate competitive or cost disadvantage among LSEs. They also identified leakage and shuffling of resources as a potential result of limiting the EPS to IOUs. More broadly, many observed that an EPS program should ideally apply to all LSEs procuring and supplying electricity resources within the State of California. For multi-jurisdictional LSE's, PacifiCorp recommends developing a methodology that takes into account their particular circumstances. Many of the ESPs commenting requested that if required to participate, a process be developed to comport with their existing reporting requirements to the Commission.

EPUC/CAC and Constellation proposed exempting co-generation QF's "so as not to discourage their development." Alternatively, their emissions should only be included to the extent they deliver energy to the LSEs. Calpine suggested that QF's be included, but that the EPS take into account their useful thermal output (converted to an equivalent MWh number) when calculating GHG emissions for purposes of EPS compliance. Such an approach would ensure that the benefits associated with the increased efficiencies of employing cogeneration technology are appropriately recognized.

The issue of cogeneration is addressed in more detail in Q13.

SB 1368 clearly requires the EPS to apply to IOUs, ESPs, CCAs, and Multi-Jurisdictional Utilities (MJUs) alike.

Section 8340(h) states, "Load-serving entity" means every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state.

Exceptions to this rule are limited to the following:

Section 8341(d)(9) states, "An electrical corporation that provides electric service to 75,000 or fewer retail end-use customers in California may file with the commission a proposal for alternative compliance with this section, which the

commission may accept upon a showing by the electrical corporation of both of the following:

(A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.

(B) The emissions of greenhouse gases to generate electricity for the retail end-use customers of the electrical corporation are subject to a review by the utility regulatory commission of at least one other state in which the electrical corporation provides regulated retail electric service."

Staff recommends that the EPS be applicable to all of the CPUC jurisdictional LSEs in compliance with Sections 8340(h) and 8341(d)(9).

The Commission's jurisdiction regarding the administration and enforcement of the EPS program is as follows:

For IOUs- Section 8341(b)(1): "The commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision (d)."

For ESPs and CCAs- Section 8341(b)(2), "The commission may, in order to enforce the requirements of this section, review any long-term commitment proposed to be entered into by an electric service provider or a community choice aggregator.

For all- Section 8341(b)(3), "The commission shall adopt rules to enforce the requirements of this section, for load-serving entities. The commission shall adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the green house gases emission performance standard to ensure compliance with the standard."

IOUs will be subject to the gateway screen. As discussed in the staff proposal, the Commission will develop a filing/review process for the ESPs that comports with their current reporting processes. However, staff amends its prior recommendation to also reserve the right to require up front review of long-term commitments by ESPs subject to the EPS.

Regarding MJUs, staff recommends modifying the staff proposal to develop a filing/approval process for multi-jurisdictional utilities (MJUs) that comports with Section 8341(d)(9).

Q18. If the Commission adopted an interim gateway EPS modeled after the Staff Straw Proposal, what documentation should it require "at the gate" with respect to 1) meeting the small size exemption, including amount of power delivered to the grid (for self-generation), 2) demonstrating whether the new commitment meets the "covered resource" definition or not, 3) claiming the cogeneration thermal load credit and 3) other requirements of the EPS?

Should there also be compliance requirements under this gateway approach (e.g., with respect to unspecified contracts), and if so, what should they be?

Respondents each had specific suggestions, but generally advised that the documentation required for the emissions factors of specified resources could be derived from information submitted by the LSEs during the contract and application processes, including data submitted to FERC and per CEQA. Several suggestions were made for obtaining additional information where necessary such as testimony during the New Resources review process or verification by an independent third party.

Staff recommends using independently verified emissions data, such as the sources described above, in estimating the emissions associated with a contract. At this time, staff does not have a particular recommendation for a specific source or sources that should be used given that it appears that relevant data could be collected from numerous objective sources, including the California Climate Action Registry (CCAR).

Q19. Staff Revised Proposal raises the issue of how to attribute emissions factors to renewable resources that have sold off their renewable energy credits (RECs) (e.g., to municipal utilities) for the purpose of applying the EPS. *There was some discussion of this “null power” issue at the workshop. Options discussed included imputing an emissions rate from the WECC region or from the region where the renewable power was located, or using the CEC’s “net system power” calculation as a default emissions rate. If you have a recommendation on this issue, please provide it in your comments.*

This issue solicited a fair amount of debate at the workshop and in comments. General recommendations provided by parties who provided written comments on this issue included: 1) allow all renewables regardless of REC status to be treated as renewable power (GPI, DRA), or 2) treatment of renewable power should mirror the RPS policy which requires a transfer of all “Renewable Attributes” to the purchasing LSE, and therefore null renewable power should not be treated as a renewable resource.

Parties who recommended that null renewable contracts be treated as devoid of renewable attributes also recommended that the null power should be considered “an unspecified resource” and treated as such (Constellation, PacifiCorp, SCE, IEPA, CRS).

While staff wishes to support renewable development and contracts, we also want to ensure that RECs and REC markets continue to maintain their validity. When a REC is sold to a third party, the expectation is that the attributes of the renewable power come with that purchase. Allowing renewable power that has been stripped of its RECs to be treated as a renewable purchase for the purpose of meeting policy goals in California would undercut the integrity and essential point of a REC market. For that reason, we recommend that null renewable resources be treated as an unspecified or system power

contract, and be subject to the same emissions factor as unspecified contracts.¹³ As discussed under Q 15 above, for the purposes of meeting the EPS, that emissions rate would be the CEC's Net System Power Average.

C. Final Staff Proposal for an Interim EPS

1) Design Goals for the EPS

- a) Prevent backsliding and commitments that will make future GHG reductions more difficult
- b) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
- c) Reliability:
 - i) short-term: do not force shutdown of essential facilities
 - ii) long-term: consider risks of relying on high emitting resources
- d) Administrative simplicity, regulatory certainty, consistency with statutory guidelines and requirements

2) Timeframe

- a) Implement program on or before February 1, 2007 in consultation with the California Energy Commission and State Air Resources Board and compliant with Section 8341(d).
- b) Coordinate with procurement proceeding, but adopt prior to February 1, 2007 per Section 8341(d).
- c) Implement performance standard as interim measure for an unspecified period of time. CPUC, through a rulemaking proceeding and in consultation with the Energy Commission and State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases EPS when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to load serving entities. (Section 8341(g))

3) To Which LSEs does the EPS apply?

- a) Apply to all jurisdictional LSEs (including ESPs and CCAs). (Section 8340(h), 8341(a))
- b) Create ESP process to address ESP procurement related to this program (Section 8341(a)(2)and(3))
- c) Don't delay pending program development for publicly-owned utilities
- d) Develop a filing/approval process for multi-jurisdictional utilities (MJUs) compliant with Section 8341(d)(9).

¹³ This does not discourage renewable power or the RECs market. The desirable emissions characteristics of the renewable generation do not disappear. Consistent with the purpose of tradable RECs, the power source that is "covered" by the RECs should be treated as renewable for the purpose of EPS calculations.

4) Program Screens

- a) The EPS standard will be applied on a “gateway” basis, at the time a LSE’s commitment (build or buy) is proposed. (Section 8341(a))
- b) The standard will be applied to the reasonably projected emission rate (lbs of CO₂ per MWh) from the supply source over the term of the commitment. (Section 8341 broadly).
- c) “Covered resources” are resources with a reasonably projected average annual capacity factor of 60% or greater. (Section 8340(a))

5) Covered Power Sources

- a) Applied to all LSE commitments (Section 8341), including:
 - i) utility owned new generation,
 - ii) repowered facilities
 - iii) new and renewal contracts for power, including cogeneration facilities
 - iv) For the purposes of ensuring that existing contracts and investments are not required to be renegotiated, all facilities that meet the requirements of Section 8341(d)(1) should be deemed in compliance at the onset of the EPS program. As contract renewals and/or repowering of those facilities occur, they should be subject to the gateway standard.
- b) All new and renewal contracts and commitments in “covered resources” of five years or longer (Section 8340(j))
- c) Applied to baseload and intermediate or “shaping” facilities with reasonably anticipated annual average capacity factor of 60% or greater (Section 8340(a))
- d) Size threshold (Section 8341 broadly):
 - i) For specified facilities (built or under contract): 25 MW or greater commitment (e.g. contract size) delivered to the grid;
 - ii) For unspecified resource/facilities under contract: 25 MW or greater delivered to the grid under contract commitment.
 - iii) For either specified or unspecified commitments: a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration.¹⁴ Multiple contracts with the same supplier, likely resource, or known facility are considered to be a single commitment, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

We recognize that some professional judgment is required to determine when certain contractual commitments are “related” or “similar” so as to

¹⁴ Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

- e) Application to Qualifying Facilities (QFs) to be determined based upon CPUC review of legal briefs and in accordance with PURPA.
- f) Facilities used for self-generation are covered if they meet the criteria for the gateway screen. Credit against emission rates for co-generation thermal loads will be permitted using the calculation proposed by EPUC/CAC and reviewed on a case-by-case basis upon a showing of the percentage of facility's useful thermal load.
- g) Renewables compliant with the RPS are covered resources subject to the gateway screen and should estimate their emissions in a manner compliant with Section 8341(d)(4). In the case of renewable contracts with firming resources, see below.
- h) Reliability and cost exemptions may be permitted, and will be considered on a case-by-case basis. The Commission will consult with the Independent System Operator to consider the effects of the standard on system reliability and overall costs to electricity customers. (Section 1(g), Section 8341(d)(6)).

6) What is the Standard and How Determined?

- a) Emissions standards based upon CCGT performance of a powerplant that is designed and intended to provide electricity generation at an annualized plant capacity factor of at least 60 percent. (Section 8340(a)).
 - i) One standard for all covered facilities based upon typical combined cycle natural gas facilities operating in the WECC system. The standard limit is 1100 lbs CO₂/MWh.
- b) Potential R&D exemption on a case-by-case basis for higher emitting facilities. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions¹⁵, and that has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement. In addition, carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the EPS. (Section 8341(d)(5)).

7) Application of the standard to units and contracts (Section 8341 broadly)

- a) Single-unit-specific contracts: contracted unit must qualify
- b) Multi-unit contracts: each covered unit must qualify
- c) Baseload renewable product with a firming fossil unit(s) that qualifies as a "covered resource": baseload blended average of all covered facilities (renewable

¹⁵ In the response to Data Request Q3, parties indicated an average heat rate of 8630 btu/kWh and emissions rate of 1770 lb CO₂/MWh for IGCC facilities.

and fossil) must pass screen. If firming unit is unspecified impute appropriate emissions factor.

- d) Null renewable power treated same as unspecified power. RPS compliant power treated as renewable.
- e) Unspecified resource contracts: apply most current CEC “Net System Power” average at time of new or renewed commitment. This is the statewide system average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a CA utility, and is the most representative option reflecting CA LSE procurement activities. All LSEs would use the same average emissions factor, regardless of location in the state.
- f) For either specified or unspecified commitments: as discussed above in 5)d.iii., a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration. Multiple contracts with the same supplier, likely resource, or known facility are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

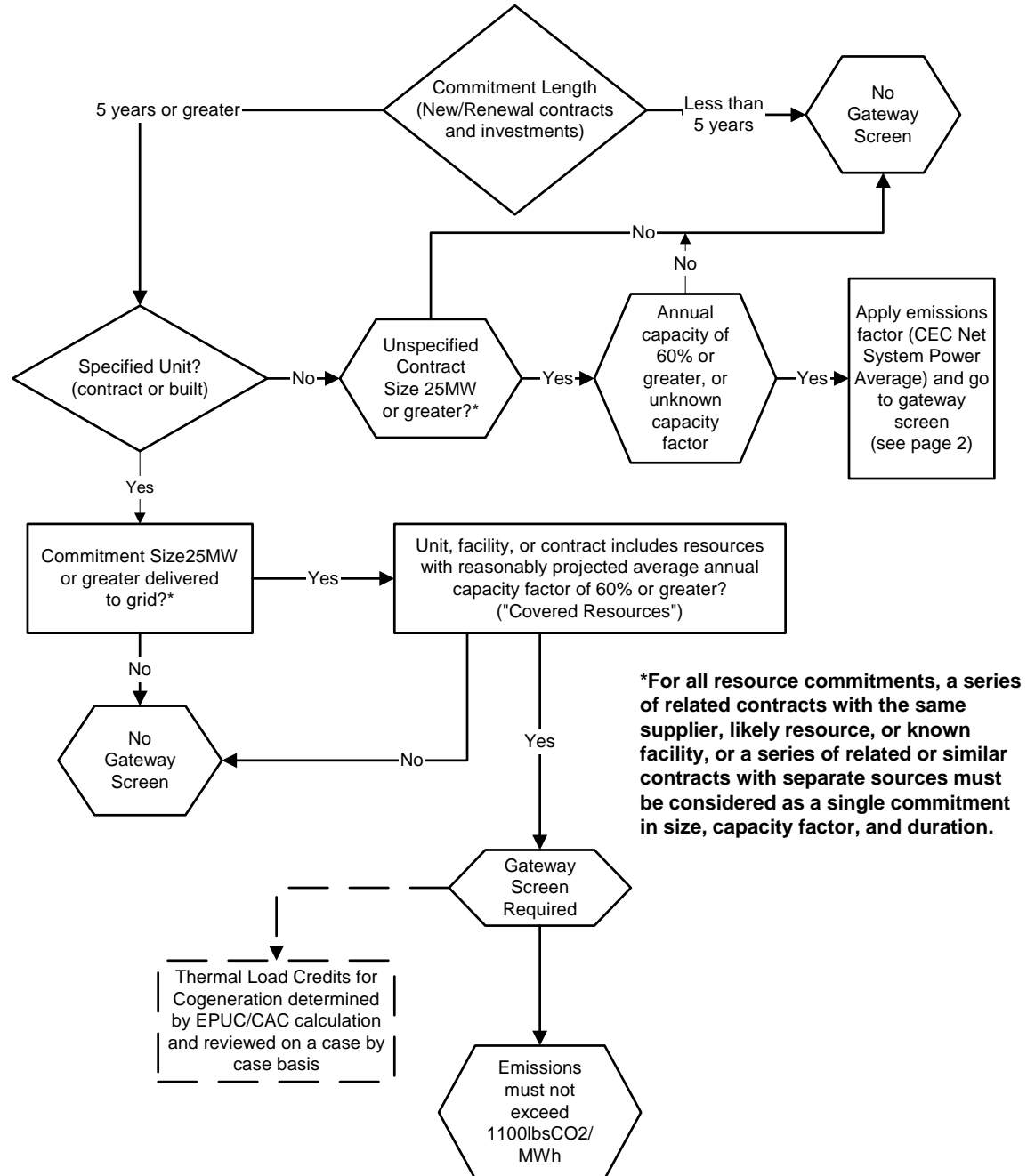
8) Monitoring and Enforcement (Section 8341 broadly)

- a) CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

9) Offsets, Safety Valves, and other flexibility devices

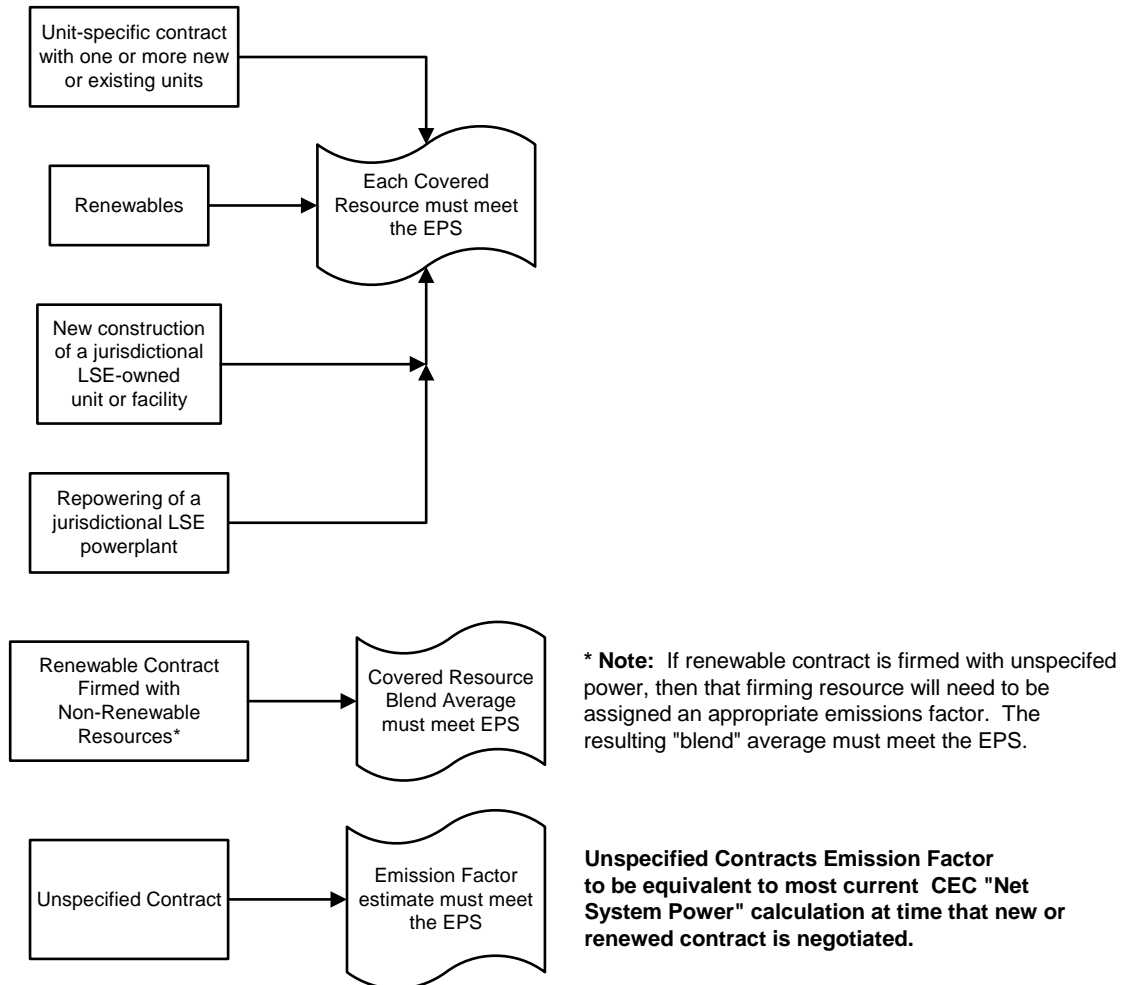
- a) No offsets or market price safety valves
- b) Case-by-case exemption for reliability and costs considered upon application and CPUC review.

EPS Screen – Covered Commitments

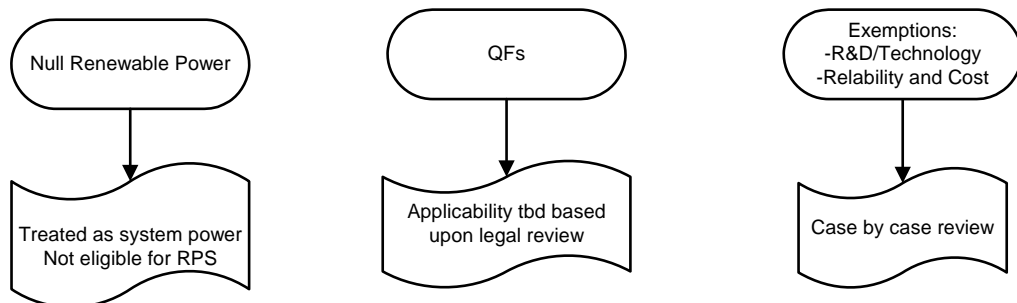


Emissions standards based upon CCGT performance
for facilities built in the last 25 years: 1100lbsCO₂/MWh

Contract and Unit Specific Requirements to Meet EPS



Other Issues



Appendix A

EPS Post-Workshop Comments

NOTE: This summary of comments is organized based upon subject area and parties' comments are organized accordingly.

- | | |
|-------------------|--------------------------|
| 1. PG&E | 10. Carson Hydro Project |
| 2. CEED | 11. Pacificorp |
| 3. EPUC/CAC | 12. SCE |
| 4. Sempra Global | 13. SF Community Power |
| 5. SDG&E/SoCalGas | 14. GPI |
| 6. Constellation | 15. CA Cogen Council |
| 7. Calpine | 16. IEPA |
| 8. DRA | 17. NRDC/TURN/UCS |
| 9. AReM | |

Comments on Draft Proposal

1) Design Goals for the EPS

- a) Prevent backsliding and commitments that will make future GHG reductions more difficult
- b) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
- c) Reliability:
 - i) short-term: do not force shutdown of essential facilities
 - ii) long-term: consider risks of relying on high emitting resources
- d) Administrative simplicity, regulatory certainty

SCE:

PG&E: generally agrees with the priorities listed in the Draft Report, subject to the need for the Commission to adjust priorities consistent with the procedural and substantive requirements of SB 1368 and AB 32.

SDG&E/SoCalGas: SDG&E and SoCalGas believe that the Revised Staff Proposal reflects Staff's responsiveness to parties' concerns regarding the design of an effective EPS. While fully supporting the prospective "gateway" approach, as well as the administrative simplicity afforded by the focus on large, long-term baseload contracts, SDG&E and SoCalGas do recommend a limited number of modifications to the Revised Staff Proposal intended to increase the reasonableness and clarity of the proposal, and the Commission's flexibility in implementing it.

NRDC/TURN/UCS/WRA: The EPS addresses the last critical element of the loading order, which prioritizes clean, efficient fossil generation, is entirely consistent with the EAP, and is critically needed. If California LSEs built or contracted for just four of the

over 30 old generation technology coal-burning power plants being proposed in the West, these plants would emit over 13 million tons of carbon dioxide per year, obliterating all the anticipated carbon dioxide savings from the CPUC-regulated IOU energy efficiency programs now through 2013. We believe the most important design goals of the EPS are to protect Californians from the significant financial and reliability risks associated with additional investments in highly carbon-intensive generating technologies, to help meet the state's greenhouse gas (GHG) reduction goals. The updated staff proposal also includes these as top-priority goals. We also strongly support the goal of administrative simplicity.

EPUC/CAC: support these goals and will point out in these comments where they are important in driving design decisions. Particular emphasis should be given to the goal of preserving existing facilities which are essential to supply sufficiency. This includes all gas-fired cogeneration facilities, which supply 17% of the generation capacity in the state. There are many indications that California will continue to need every MW of available capacity to meet native load. As an interim measure, the EPS should be designed to prevent the addition of long-lived generation stock that would contribute to a higher level of GHG than would be produced by gas-fired generation. SB 1368 directs the Commission to ensure reliability is not threatened by requiring consultation with the California Independent System Operator (ISO). Sec. 8341(d)(6). EPUC/CAC urge the Commission and the ISO to undertake a rigorous analysis of the available generation and the effect of either eliminating some generation or moving it to the spot market. Another important goal is to implement an EPS only if it does not contribute to material rate increases to ratepayers or to price volatility for the LSEs. In complying with an EPS, California utilities will be required to purchase only from a discrete subset of potential suppliers. This naturally decreases the supply pool, thus increasing the price for California utilities. However, if the energy from those suppliers is necessary to meet load, the LSEs will ultimately buy from them, but on a short-term or spot basis. This procurement conduct will exacerbate volatility. To prevent such risks of price volatility, EPUC/CAC recommend maximizing measures to ensure the continued availability of efficient gas-fired generating facilities.

SFCP: Recommended Additional Design Goals:

- The interim EPS should not interfere with the development and implementation of a load-based cap-and-trade program as specified in D.06-02-032, Order No. 1 or a market-based compliance mechanism as specified in Health and Safety Code (H&SC) Sections 38505(k) and 38570.
- The interim EPS should not interfere with the potential for California-based LSEs to participate in transactions with participants in the Northeastern U.S. "Regional Greenhouse Gas Initiative" (RGGI) or the European Union's "European Trading Scheme" (EU ETS).

2) Timeframe

- a) Coordinate with procurement proceeding, but adopt now
- b) Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program, including consideration of ending the

program, when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

SDG&E and SoCalGas: The Revised Staff Proposal should be modified slightly to state that the need for an interim EPS will be reevaluated in light of adoption of an enforceable GHG emission limit. This modification reflects the fact that Phase II does not contemplate a “cap-and-trade” system among the three utilities for the reasons detailed in D.06-03-032, but does consider enforceable GHG emissions limits and market-based compliance mechanisms such as offsets that could substantially change the role of the EPS. In addition, SB 1368 requires reevaluation of the EPS “when an enforceable greenhouse gases emissions limit is established and in operation . . .”

NRDC/TURN/UCS/WRA: Neither SB 1368 nor coordination with the procurement proceeding should prevent the PUC from meeting the schedule laid out for Phase 1 of this proceeding and adopting the EPS according to its existing schedule. We support the staff proposal to adopt and implement the EPS without a specific sunset date. EPS must be in place at least until an enforceable limit on electricity sector greenhouse gas emissions is instituted. Until a specific mechanism is actually designed and implemented, one cannot predict whether and in what form we may need to continue the EPS. Therefore, it would be premature to artificially limit the EPS, and in fact doing so would actually muddy the clear signal this policy sends to the market. The staff proposal also is entirely consistent with language in SB 1368, which states that the CPUC “shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases limit is established and in operation, that is applicable to load serving entities” (Section 8341(g))

EPUC/CAC: The interim nature of the proposed mechanism would mitigate some of the risks posed by the program, particularly those risks created by adopting the mechanism very expeditiously without an opportunity for any rigorous analysis and modeling. However, if the mechanism is adopted for “an unspecified period of time” without any definite procedure for termination, it becomes less of an interim measure. This section of the proposal should be revised to reflect the provisions of SB 1368. The proposal should state that the CPUC “*shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation.*”

Constellation: In this Workshop Report, the Staff has recommended an interim EPS that will likely impact a significant amount of generation in California while it is in effect. While the Workshop Report intends to provide mechanisms to make sure reliability is not threatened by the interim EPS, Constellation remains concerned that without an effective region-wide cap-and-trade program in place, the costs of environmental compliance for Californians are likely to be much higher than they need to be. Constellation respectfully suggests that California ratepayers and California’s energy market participants will be well-served by an expeditious implementation of regional and multi-sector mechanisms that provide a maximum amount of flexibility in meeting GHG emissions reduction

standards. The adoption of flexible compliance mechanisms will facilitate the development of optimally efficient and cost effective emission reduction. Thus, Constellation requests that the Workshop Report and the Commission Order provide a procedural schedule by which such mechanisms will be evaluated and implemented.

3) To Which LSEs does the EPS apply?

- a) Apply to all jurisdictional LSEs (including ESPs and CCAs)
- b) Create ESP process to address ESP procurement related to this program
- c) Don't delay pending legislation regarding publicly-owned utilities
- d) Develop a filing/approval process for multi-jurisdictional utilities (MJUs), including a protocol for allocating emissions among resources serving multiple states. Consideration given to MJUs that have prior approvals from other jurisdictions for integrated resource plans (IRP) that include adequate provisions for climate change

PG&E: SB 1368 has resolved this.

NRDC/TURN/UCS/WRA: We support the staff proposal in applying the EPS to all jurisdictional load-serving entities (LSEs). We note that SB 1368 specifically supports the staff proposal and requires that the EPS apply to ESPs and CCAs, as well as publicly-owned utilities. We recommend that the process of compliance for multi-jurisdictional utilities (MJUs) should be consistent with SB 1368's stipulations for LSEs with 75,000 or fewer customer in the state (§8341.d.2.9). However, SB 1368 goes further than this. It requires that the actual "emissions of greenhouse gases" are subject to review by at least one other utility regulatory commission, and not simply that the emissions of greenhouse gases are divided up among the respective state jurisdictions afterwards. We also encourage the Commission to allow opportunities for public comment on these proposals for alternative compliance as they are considered and implemented.

PacifiCorp: supports the staff recommendation to develop a filing/approval process for multi-jurisdictional utilities (MJUs), including a protocol for allocating emissions among resources serving multiple states. We also agree that consideration should be given to MJUs that have prior approvals from other jurisdictions for integrated resource plans (IRPs) that include adequate provisions for climate change. We interpret "adequate provisions" to be a breadth of policies ranging from the use of a carbon adder within IRP-based resource addition decisions to state-specific regulation of carbon dioxide emissions. We also observe that the recently passed Senate Bill 13681 allows an electrical corporation that provides electric service to 75,000 or fewer retail end-use customers in California to also file with the commission a proposal for alternative compliance, which the commission may accept upon a showing by the electrical corporation of both of the following:

A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.

B) The emissions of greenhouse gases to generate electricity for the retail end use customers of the electrical corporation are subject to a review by the utility regulatory

See § 8341 (d)(9). commission of at least one other state in which the electrical corporation provides regulated retail electric service.

We interpret step B's "subject to review" test to be satisfied when 1) a state jurisdiction requires a utility to review and report on the potential impacts of different carbon policies within its IRP process; 2) when it requires the utility to disclose its greenhouse gas emissions or expected change in overall emissions as a result of changes to its portfolio, including new capacity additions; or 3) when another jurisdiction adopts rules specifically regulating emissions of greenhouse gases from electricity generating facilities.

4) Program Screens

- a) The EPS standard will be applied on a "gateway" basis, at the time a LSE's commitment (build or buy) is proposed.
- b) The standard will be applied to the reasonably projected emission rate (lbs of CO₂ per MWh) from the supply source over the term of the commitment
- c) "Covered resources" are resources with a reasonably projected average annual capacity factor of 60% or greater.

PG&E: As discussed in its previous comments, PG&E agrees with the "gateway" standard included in the Draft Report, subject to more up-front specificity on the documentation required to demonstrate compliance (see Question 18, below). As stated in PG&E's June 12 pre-workshop comments, the EPS should be applied only at the time of each load serving entity's (LSE's) decision to procure, certify or legally commit to a baseload generating facility or contract subject to the EPS. Compliance would be demonstrated up-front, at that time only, through documentation of the facility's full load heat rate and expected capacity factor, so that there would be regulatory certainty and predictability for the LSE, the Commission and the LSE's customers generally.

NRDC/TURN/UCS/WRA: We support the "gateway" approach and the covered resources definition. We recommend that the Commission change the language "reasonably projected," both in section 4b and 4c, to be consistent with SB 1368, which defines baseload generation (or the "covered resource" in the staff proposal) as "electricity generation from a powerplant that is *designed and intended* to provide electricity at an annualized plant capacity factor of at least 60 percent" (emphasis added).

DRA: recommends a slightly lower but reasonable average annual capacity factor (50% vs. DSP's recommendation of 60%) as the cut off for baseload. The staff report's argument that the marginal difference in energy and pollution is small between the two is not relevant.⁵ In fact, if the difference is negligible, then it makes no difference which cut-off is adopted. The important factor is the relative reduction in CO₂ emissions compared to the relative energy produced. By this measure, each kWh produced by plants operating at a 50% capacity factor produces more CO₂ emissions than a kWh from the power plants operated above a 60% capacity factor. The utilities did not make a case as why the 60% (as opposed to 50%) cut-off was necessary. In the event the Governor signs SB 1368, then it appears that the issue will be resolved by Sections 8340 and 8341 of the

Public Utilities Code, which would prohibit load serving entities from entering into long term financial commitments for baseload generation, defined as “generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.”

EPUC/CAC: In Sec. 4(c), the definition of the capacity factor should be revised to reflect the definition from SB 1368. It should include resources “*designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.*”

The proposal must also clarify how the capacity factor screen will be applied to contracts. For instance, a facility serving industrial load under Public Utilities Code §218(b) may operate at greater than a 60% capacity factor, but it may only on an irregular basis deliver to the grid excess energy above its on-site use. Thus, while physically it may operate at or above a 60% capacity factor, its actual deliveries to LSEs may have a capacity factor much less than 60%. The EPS should not be applied to those deliveries. To provide this clarification, the Proposal should be modified to state: “*Covered resources’ also include a contract of five years or more to deliver firm energy to a utility in an amount equal to the MWh that would be produced by the generator if operating at an annual plant capacity factor of at least 60%.*”

GPI: We encourage the Commission to go beyond the minimal obligations imposed by the new legislation, and include high-use intermediate and shaping facilities in the definition of covered resources, as originally intended. If the Commission chooses this course, a threshold annual capacity factor of 50 percent is more appropriate to use as the definition of covered resources.

5) Covered Power Sources

- a) Applied to all new utility commitments, including:
 - i) utility owned new generation,
 - ii) repowered facilities
 - iii) new and renewal contracts for power

PG&E: EPS should only apply to at the time of an LSE decision to procure, certify or legally commit to a baseload generating facility or contract. Recommends that only those changes to a powerplant that result in a net increase in the rated capacity of the plant be considered as changing the status of the facility from being deemed in compliance to being required to demonstrate compliance. This is consistent with the grandfathering policy for existing CCGTs in SB 1368. Five year or longer contracts are also required by SB 1368.

NRDC/TURN/UCS/WRA: We recommend that the Commission explicitly clarify in section 5a that the standard will also apply to major renovations of utility-owned facilities, as we recommended in our post-workshop comments. Major renovations fall under SB 1368’s definition of a “long-term financial commitment” as “either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years.”

Constellation: If the Commission is indeed going to apply the interim EPS to all resource commitments that are of five years or greater duration with resources that operate in baseload fashion, the issues of whether and how the gateway will be applied to utility retained generation must be specifically addressed. Otherwise, under the Revised Straw Proposal, utility retained generation would simply never trigger the gateway screen, because utility retained generation does not enter into the type of contractual commitments that trigger the EPS review. Rather, these utility retained assets operate pursuant to rate regulation that provides for cost recovery and a return while the asset is used to serve utility load, usually for the life of the asset. That regulatory “contract” is not subject to renewal as are contracts with non-utility owned generation, and therefore existing utility retained generation will effectively avoid application of the screen after the initial commitment. One could argue that the regulatory compact afforded to utility retained generation automatically should trigger the gateway screen review, and that is one potential solution to this issue – i.e., that all utility retained generation must be subject to the screen automatically upon implementation of the EPS, given that they enjoy a “regulatory contract” that is greater than 5 years in duration (unless, of course, it can be shown that the facility is not expected to be in operation pursuant to rate regulation for more than the next five years). Put simply, a decision to apply the interim EPS via contractual commitments only should not create a *de facto* loophole for all utility retained generation. Constellation thus requests that the Workshop Report be amended to provide a mechanism by which generation owned and operated by the IOUs will be subject to the gateway screen adopted in the interim EPS.

- b) All new and renewal contracts and commitments in “covered resources” of five years or longer
- c) Applied to baseload and intermediate or “shaping” facilities with reasonably anticipated annual average capacity factor of 60% or greater

PG&E: agrees with the Draft Report’s recommendation that partial year contracts not be covered by the EPS. PG&E believes the 60% capacity factor should be and is required by SB 1368 to be applied on an annual, not seasonal, basis. (See SB 1368, new Public Utilities Code section 8340(a), (l).) To calculate the 60% capacity factor on a seasonal basis blurs the distinction between baseload and peaking products, and may inadvertently take away important contractual alternatives for providing reasonable energy supplies at reasonable cost.

NRDC/TURN/UCS/WRA: Page 24 of the draft workshop report states, “Staff recommends that partial-year contracts for shaping resources that have less than a 60% capacity factor on an average annual basis not be covered by the EPS because of the seasonal reliability issues that they address. It is important to note that this distinction is based up the size and expected capacity factor of the commitment (and thus its GHG emissions), not its name or degree of dispatchability.” From our understanding, this means that a “summer product” from a specified pulverized coal plant could conceivably pass the EPS, which runs contrary to the goals of the EPS of limiting significant financial and reliability risks from high carbon-emitting resources. There is absolutely no need for such an exemption for partial contracts. As we explain above, *all* contracts should be

analyzed by looking at the operation of the facility behind the contract. If a partial-year contract is really intended to address short-term reliability concerns, then the contract would probably be less than five years in length, and thus would not even go to the gate for consideration under the EPS. If the contract is a recurring annual partial-year contract for more than five years, then it is a long-term financial commitment that should definitely be evaluated at the gate. We suggest changing “reasonably anticipated” in section 5c to “designed and intended.”

EPUC/CAC: Determination of whether a facility is a “baseload” facility must examine the facility’s deliveries to one or more LSEs, rather than its design or actual physical operation.

Constellation: requests that the Workshop Report be clarified with respect to how the gateway screen is triggered for contracts that provide for energy deliveries for only a portion of each year that the contract is in effect. Specifically the question remains: For a contract that does not require energy deliveries during some months of a year, is the capacity factor presumed to be “zero” during the months when there are no deliveries, thus reducing the calculated average capacity factor of the unit, and potentially exempting that unit from the gateway screen (even if another entity has entered into a contract with the same unit for the output in the “zero” months)? Or, alternatively, is the capacity factor for the months when no deliveries are required subject to some assumed capacity factor in order to determine whether that unit triggers the gateway screen? Clarity about these rules is necessary so that parties may structure their transactions appropriately.

GPI: There is no reason to make a distinction between partial procurements based on horizontal or vertical slices of a facility’s output. The principle should be the same—look to the underlying generating resource. The straw proposal already includes a provision to grant an exemption for reliability considerations (properly so, in our opinion), so if there is a reliability case to be made for a particular procurement, there is already a mechanism in place for an exemption to be granted. A blanket exemption for seasonal procurements is both unnecessary, and inconsistent with other aspects of the proposed interim EPS rule. Seasonal procurements, like all partial procurements, should be judged at the interim EPS gateway on the basis of the underlying facility. If a particular proposed procurement deserves a reliability exemption, then an exemption should be granted, based on the merits of the case.

IEPA: respectfully disagrees with staff’s conclusion on the issue of partial-year contracts. The baseload threshold criteria should apply to the actual operation of the resource underlying the contract. For example, an out-of-state coal plant might enter into a long-term contract to provide baseload power to a California Load-Serving Entity (“LSE”) for the months of May through October. This unit could also sell its output to another buyer (either an out-of-state buyer or a different California LSE) for the months of November through April. Even if the unit underlying this contract were to run at or near a 100% capacity factor level (certainly not a “shaping” resource by any stretch of the

imagination), staff's recommended annual average basis for evaluation would show this resource to have less than a 60% capacity factor and thus not be subject to the screen.

d) Size threshold:

PG&E: agrees with the Draft Report's recommended threshold of greater than 25 MW for both specified and unspecified contracts, with the emissions factor for unspecified contracts imputed based upon the contract size rather than the emissions rates of the underlying facilities.

NRDC/TURN/UCS/WRA: the staff proposal indicates that the size threshold should apply to the "commitment (e.g. contract size) delivered to the grid" for specified facilities or under contract. We think the size threshold should be applied to the underlying facility, *not* the contract or amount delivered to the grid. A size threshold of 25 MW (applied to the underlying facility as we propose), would not capture highly carbon-intensive emitting facilities, which are sometimes just under 25 MW in size, but that still present significant financial and reliability risks. We recommend the Commission instead adopt a size threshold of 5 MW in section 5d, consistent with the maximum size limit under the Self Generation Incentive Program. In addition, a size threshold should not be applied to any contracts, specified or unspecified.

i) For specified facilities (built or under contract): 25 MW or greater commitment (e.g. contract size) delivered to the grid;

PG&E: Where long-term, baseload contracts of 25 MW or greater identify specific units, PG&E agrees that the forecast capacity factor and the heat rate at ISO conditions of the particular unit should be used for the EPS. PG&E further agrees with the Draft Report that the EPS would not apply to those units whose capacity factor is less than 60% regardless of the type of contract. Therefore, peaking units named for reliability and back-up purposes in a baseload contract would be screened using the expected capacity factor of the unit, rather than the contract. To be consistent with SB1368, CCGTs in operation or with a final permit decision to operate as of June 30, 2007 would be deemed compliant with the EPS.

EPUC/CAC: agree with the Staff Proposal that a size threshold should be established for application of the EPS. Ideally, however, the threshold would be set at MWh or energy delivered rather than on MW of capacity. As pointed out previously, emissions arise from MWh generated, not from MW of capacity. For this reason, EPUC/CAC proposed a threshold of 200,000 MWh annually.

If, however, Staff declines to take this approach it should clarify the operation of its proposed threshold. The Proposal should be clarified to provide that a facility may deliver under this standard effectively up to 219,000 MWh a year, assuming a 100% capacity factor (25 MW x 8760 hours x 100%).

- ii) For unspecified resource/facilities under contract: 25 MW or greater delivered to the grid under contract commitment.

PG&E: For contracts 25 MW or above which do not specify particular units, if the contract references a contract heat rate, then this contract heat rate should be used to establish compliance with the EPS. If the contract does not establish a contract heat rate, then the contract emissions rates should be imputed using the CEC net power calculation.

- iii) For either specified or unspecified commitments: a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration.¹⁶ Multiple contracts with the same supplier, likely resource, or known facility are considered to be a single commitment, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

We recognize that some professional judgment is required to determine when certain contractual commitments are “related” or “similar” so as to trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

PG&E: supports the staff’s proposal to not apply the EPS to de minimus contracts of less than 25 MW and concurs with the establishment of rules to avoid “gaming.” If an LSE enters into a simultaneous series of contracts with a unit that increase the capacity factor, contract length, or contract size above 25 MW, then these contracts should be treated as one financial commitment with the unit.

NRDC/TURN/UCS/WRA: In section 5.d.iii of the staff proposal, as well as 7.f and 7.g, the staff proposes a prohibition of “multiple contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources” by considering them as a single contract to prevent “slicing and dicing” of large contracts into forms that would slide past the EPS. The staff proposes to enforce this requirement and assess a penalty to LSEs that do not disclose these contracts. Although

¹⁶ Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

we agree that slicing and dicing is a serious concern, we do not believe this is the most efficient way to handle the potential problem.

We believe this approach of monitoring “sliced and diced” contracts is counter to the goal of administrative simplicity. A system of ongoing monitoring of contracts and assessment of penalties would simply increase the administrative burden of the EPS. It is unclear to us how this enforcement would take place, as multiple contracts could occur at different times, or multiple California LSEs could agree to team up for multiple small contracts, and thus they would be impossible to track. In addition, designing a system with penalties would defeat the purpose of having a standard; if the standard is not met, assessing a penalty will not correct the failure to meet the standard, as the long-term commitment will already have been made. A “professional rule of reasonableness” is not sufficient to protect Californians from significant financial and reliability risks associated with high-emitting resources.

We strongly recommend that the Commission not adopt this multiple contract enforcement and penalty aspect of the staff proposal. Instead, the Commission should make the EPS easier to enforce and more effective through upfront enforcement and by clarifying that the standard applies to the underlying facility(ies) behind contracts. This is also consistent with the direction in SB 1368 as noted above.

Constellation: It should be clear that only contracts that are between the same parties could be called “related contracts.” More specifically, it should be clear that if two different entities (that are not affiliated with one another) enter into separate contracts with a unit owner for output from the same facility, those two separate contracts cannot be deemed to be “related contracts.”

e) [Application to Qualifying Facilities \(QFs\) to be determined based upon CPUC review of legal briefs and in accordance with PURPA.](#)

PG&E: SB 1368 has resolved this issue, by applying the EPS to all load serving entities and local publicly owned utilities serving end-use customers in the state.

Sempra Global: believes that, to be effective, the EPS must apply to every resource providing baseload power to one or more California load-serving entities, including QFs and renewables. Subdivision (d)(3) of newly enacted Public Utilities Code² section 8341 directs the Commission to develop a methodology to calculate GHG emissions from both the electrical and thermal output of QFs, and subdivision (d)(4) provides direction on how the GHG emissions from renewables are to be calculated. Sempra Global submits that an exemption for either QFs or renewables would be contrary to the purpose of the EPS and not in the public interest. Given the state’s RPS statute and goals, it is not reasonable to conclude that the EPS will hinder development of renewables projects. Indeed, one would expect renewables development to accelerate as the Commission finalizes its rules for RPS implementation for ESPs, and as new transmission projects come online that are engineered, in part, to facilitate the delivery of renewables output. Further, neither the Commission nor the Energy Commission nor the legislature can reliably assess the success of the EPS if certain classes of generators are exempt from its

requirements. It may be that there are other public policy reasons why the Commission or Legislature may decline to enforce the EPS, but there should be no blanket exception.

EPUC/CAC: In Sec. (e), the Proposal should address the scope of applicability of the EPS to QFs. While the issue of exempting QFs as a class may be a legal issue awaiting decision, there are policy reasons for designing the EPS so that it does not apply to certain types of cogenerators. As noted above, it is reasonable and necessary to avoid discrimination to deem existing gas-fired cogeneration in compliance with the standard as the Commission must do for all CCGTs.

In addition, another policy basis exists for deeming in compliance a unique form of cogeneration: bottoming-cycle cogeneration. Bottoming cycle units use waste heat from an industrial process, such as calcining, and produce electricity. For example, in the process of calcining petroleum coke as a necessary part of petroleum refining, heat is produced. That heat can either be vented into the atmosphere or captured for the production of electricity through a steam turbine. In other words, no fuel is burned to produce electricity; any fuel used is attributable to the industrial process of producing calcined coke. Emissions from that process will be addressed in any rules ultimately adopted for the petroleum sector under AB 32.

Consequently, it is unclear how, if at all, an EPS could be effectively applied to bottoming cycle generating facilities from the standpoint of jurisdiction and pure mechanics. At the same time, it is clear that there are few or no CO₂ emissions produced by the simple use of industrial thermal energy to generate electricity in a steam turbine. In light of the difficulty of applying an EPS in this setting and the absence of material CO₂ emissions from bottoming cycle facilities, bottoming-cycle cogeneration plants should be deemed in compliance with any adopted EPS.

CCC: can support the Draft Report's "new commitment" approach, provided it is applied in a fair and non-discriminatory fashion to all resources, including both utility-owned and independent generators. Thus, if the Commission decides that an interim EPS should apply to existing QFs and other merchant plants, then such a standard also should apply to existing utility owned resources. The CCC recommends that each existing, baseload utility owned unit larger than 25 MW should be required to show that it meets the interim EPS at least once every 10 years, or whenever the unit is repowered or major equipment is replaced or added.

IEPA: Regarding QF's, the EPS should not apply to new commitments or renewed commitments with power plants developed consistent with the Public Utilities Code Sections 2801-2821 or the Public Utility Regulatory Policies Act ("PURPA"), and which began operation prior to January 1, 2006.

- f) Facilities used for self-generation are covered if they are reasonably expected to supply power to the grid above the threshold levels (size, duration, and capacity factor) set in the Rule for other facilities. Credit against emission rates for co-generation thermal loads will be permitted on a case-by-case basis upon a showing of the percentage of facility's useful thermal load.

PG&E: also supports the Draft Report’s proposal that the exemption be based on MWs delivered to the grid, and that any thermal credit for self-generation resources be demonstrated on a case-by-case basis. Agree that emissions credits for thermal side of cogeneration facilities be reviewed and approved on a case-by-case basis. In addition, consistent with the interim nature of the EPS and the “safety valve” provisions of AB 32’s “cap and trade” program, PG&E recommends that the EPS include an opportunity for a case-by-case exemption to be granted for a specific facility or procurement contract if the LSE demonstrates that the exemption is needed in order to avoid severe economic impacts or electricity market disruption to the detriment of retail electricity customers.

SDG&E/SoCalGas: While the conclusion that each cogeneration project has a different thermal application and that some case-by-case analysis will be required is correct, it is not the case that the methodology itself can be determined on a case-by-case basis. Rather, the methodology should be clearly defined at the outset in order to avoid delays, inconsistencies and confusion down the road. Rather than creating an unnecessary ambiguity, the EPS should expressly define the calculation method and not leave this question open to be decided when the first contract is presented to the Commission for approval. SDG&E and SoCalGas proposed a clear and easy to implement methodology based upon deducting the emissions associated with the useful thermal load in their pre workshop and post-workshop comments. The emissions associated with the thermal load are calculated as if the thermal application was separate from the electricity production. The emissions associated with useful thermal energy are deducted from the overall emissions of the cogeneration unit assuming a standard efficiency boiler. The calculation is simple and straight-forward, and has been used for air quality purposes by Rhode Island. If the Commission wishes to more fully evaluate alternate methods in Phase II, it could adopt the SDG&E method solely for purposes of the interim EPS and indicate its intent to revisit the issue in Phase II.

NRDC/TURN/UCS/WRA: we do not support applying the threshold levels of the EPS (size, duration, and capacity factor) only to the amount of power supplied to the grid from self-generators. Doing so runs contrary to the conditions laid out in SB 1368 that stipulate that the EPS be applied to “any baseload generation supplied under the long-term financial commitment,” without any exemption for self-generation. If an LSE buys power from a self-generation facility, no matter the size of the commitment, the facility is still a resource upon which it relies and will contribute to ongoing financial and reliability risks if the facility does not meet the standard. Instead, a self-generation facility is also an example of an underlying facility to which the EPS criteria should be applied. We strongly support the staff proposal (section 5f) to credit the useful thermal load of cogeneration facilities on a case-by-case basis, and note that this is consistent with SB1368, Section 8341(d)(3): “The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy.”

EPUC/CAC: In Sec. (a), the standard should not be applied to new contracts with existing facilities, where there is no significant re-powering of the facility. At a minimum, the proposal should be consistent with SB 1368 and provide that all combined-cycle gas-fired powerplants and gas-fired cogenerators operating as of June 30, 2007 will be deemed to comply with the EPS.

Deeming all existing CCGTs in compliance with the standard goes a long way toward ensuring that existing resources are not somehow made unavailable to the California market as the State transitions to GHG regulation. The standard must be applied, however, in a manner that avoids discrimination among different types of cogeneration facilities.

It is generally accepted that cogeneration, or combined heat and power, is more efficient than other forms of natural gas fired generation. The 2005 IEPAR also noted, relevant to this proceeding, that cogeneration reduces greenhouse gases. For all of these reasons the EPS should be structured to recognize the inherent environmental and energy efficiency benefits of cogeneration.

Applying SB 1368's exemption for existing CCGT plants will capture certain cogeneration applications – those facilities that use waste heat to generate additional electricity. Other forms of gas-fired cogeneration, however, that use waste heat from industrial processes, may not meet the strict definition of “combined cycle” in SB 1368. Nevertheless, such cogeneration provides an efficient source of energy and must be preserved. As an example, some cogeneration facilities produce steam used in enhanced oil recovery, and generate electricity from the waste heat. The 2005 IEPAR specifically recommends the increased use of cogeneration to ensure the reliability of petroleum production. However, it is unclear whether such cogeneration facilities would fall within the SB 1368 definition of “combined cycle.” The waste heat from such industrial processes will be produced regardless of the implementation of the EPS; the EPS should be structured such that the maximum energy is efficiently produced from the input energy. Consequently, the Commission must clarify that all existing CCGTs and gas-fired cogeneration facilities will be deemed to comply with the interim EPS. This clarification would be consistent with the requirement in SB 1368 to allow exemptions as consistent with the PURPA mandate to encourage cogeneration. PU Code § 8341(d)(8)

The discussion of cogeneration in Sec. 5(f) implicitly leaves indefinite whether there will be a credit for thermal energy, and makes no recommendation as to methodology. There is general agreement among the parties that the total energy output of a cogeneration facility, including both electrical and thermal energy, should be utilized in calculating the emissions rate of the facility. SB 1368 likewise mandates this approach. It states in Public Utilities Code section 8341(d)(3):

The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy.

This mandate conforms precisely to the calculation previously proposed by EPUC/CAC. The workshop report should make the methodology explicit rather than requiring a case by case analysis.

The EPUC/CAC proposal continues to be the simplest method and conforms precisely to the language of Section 8341(d)(3). Essentially, the emissions rate accounts

for the total emissions of the cogeneration facility in the numerator, and includes the total energy output – both electrical and thermal converted to equivalent kWhs – in the denominator, as follows:

Total Emissions

$$\frac{\text{kWh of electricity} + \text{Btus of thermal energy converted to kWh}}{\text{Total Emissions}}$$

Btus of thermal energy are converted to equivalent kWh employing the industry standard engineering conversion factor of 3413, which was discussed extensively in EPUC/CAC's prior comments.

CCC: Although it is obviously true that each cogenerator produces a unique amount of thermal energy, it does not mean that the Commission cannot adopt a certain formula for the thermal credit calculation. Then the case-by-case review could be limited to verifying each cogeneration facility's useful thermal output, as the input to the adopted credit formula. Unless the Commission adopts a specific formula for the thermal credit, the Commission faces the potential that different utilities may use different formulas for the thermal credit calculation. The CCC strongly believes that the CAC / CCC / DRA method is the correct formula – it divides the cogenerator's total GHG emissions, in pounds of CO₂, by the facility's total output of useful energy, both thermal and electrical, expressed in common units (kWh).

Finally, the CCC observes that determining a cogenerator's useful thermal output should be very straightforward. If the cogenerator is a QF (and most are), then the cogenerator must provide the utility with its production of useful thermal energy on an annual basis, to verify the cogenerator's compliance with the FERC efficiency standards for cogeneration QFs. This information already is subject to audit by the utilities. This data on useful thermal output can be readily used to verify compliance with the interim EPS, should a cogeneration QF re-contract with a California utility. The Commission can simplify the administration of the interim EPS by approving the use of a cogenerator's existing FERC efficiency data for the purposes of compliance with the interim EPS.

- g) Renewables compliant with the RPS are exempt, unless combined with firming resources. In the case of contracts with firming resources, see below.

NRDC/TURN/UCS/WRA: Rather than exempting all RPS-compliant renewables (section 5g), we recommend that the Commission make a stipulation, based on the evidence presented by the Green Power Institute in their post-workshop comments filed on July 27, 2006, that all renewables are deemed to be in compliance with the EPS. Thus, renewables will still go to the gate, but will be "assigned an emissions factor of zero," as the workshop report discussion suggests (p.29), and thus pass the standard. Although the distinction between deemed compliance and an exemption may seem like a minor nuance, we recommend that the Commission make the distinction to accurately represent

the treatment of renewables in the EPS – namely, that they meet the standard and are not true exemptions to the rule.

h) Reliability exemptions may be permitted, and will be considered on a case-by-case basis

PG&E: PG&E recommends that the EPS include an opportunity for a case-by-case exemption to be granted for a specific facility or procurement contract if the LSE demonstrates that the exemption is needed in order to avoid severe economic impacts or electricity market disruption to the detriment of retail electricity customers

SCE: Amend 5 (h) to say: Thus, Section 5(h) of the Revised Staff Proposal should be amended as follows: 5) Covered Power Sources h) Exemptions may be permitted on a case-by-case basis, such as for system reliability concerns and considering overall costs to electricity customers.

NRDC/TURN/UCS/WRA: As we stated in our post-workshop comments (p. 21-22), we believe that the EPS as we have proposed has been designed specifically to avoid reliability concerns and in fact is designed to protect Californians from long-term reliability risks. Based on the purposeful design of the EPS (five year long-term commitments, 60% annualized capacity factor that is intended to exclude shoulder or peaking plants, and upfront approval only without ongoing monitoring), any consideration for reliability exemptions to the EPS should come with a heavy burden of proof on the LSE and a public process for consideration of the granting of the exemption.

CEED: The Draft Report attempts to address reliability concerns by allowing reliability exemptions on a case-by-case basis, but misses the much larger policy issue created by eliminating most new resource options and forcing the state to become increasingly dependent upon natural gas. *At the minimum, the Draft Report should contain a discussion of anticipated compliance costs and reliability impacts and how (if at all) the proposed approach minimizes ratepayer costs and risks.*

6) What is the Standard and How Determined?

a) Emissions standards based upon CCGT performance at ISO levels.

NRDC/TURN/UCS/WRA: We recommend that the Commission clarify what is intended by the staff proposal to determine the emissions standard “based upon CCGT performance at ISO levels” as it is unclear to us what “ISO levels” means.

i) One standard for all covered facilities: equal to a high-performing new CCGT as discussed in the data request. The standard limit is 1000 lbs CO2/MWh.

PG&E: PG&E believes that the standard chosen by the staff of 1,000 lbs CO2/MWh is too stringent to meet all of the policy goals enumerated above. Based on data provided by the parties to the staff and the need to maintain reliability with shaping, intermediate resources with efficient heat rates, PG&E supports the standard of 1,100 lbs CO2/MWh

proposed by NRDC, TURN, UCS, GPI, and SDG&E, not 1,000 lbs CO₂/MWh as recommended by the Draft Report.

SDG&E/SoCalGas: The main value of an interim EPS lies in the information supplied to generation developers. SDG&E and SoCalGas agree that a single standard, such as that proposed in the Revised Staff Proposal, provides an unambiguous standard and a clear signal to generation developers. EPS should be at least 1,100 pounds of GHG per MWh so as to insure that all CCGTs will pass the EPS. As an initial matter, SDG&E and SoCalGas note that setting the EPS at a level that will ensure passage by all CCGTs is consistent with the direction provided in SB 1368. Moreover, the Draft Workshop Report's conclusion that 1,000 pounds per MWh is the appropriate measure appears to be predicated on the assumption that most CCGTs will meet that standard. This is not the case, however. Based on the data developed in the proceeding, the high end of the range for CCGT units from the "heat rate and emissions w/vintages" table is 1,020 pounds per MWh. The highest measured emissions for a CCGT with a 60 percent or above capacity factor per the "summary table" is 1,058 pounds per MWh. The Draft Workshop Report also cites an upper value for gas plants operating in California with a capacity factor above 60 percent to be 1,006 pounds per MWh. All of these values exceed the Staff proposed 1,000 pounds per MWh. The Draft Workshop Report relies upon the argument that 1,000 pounds per MWh is well above the average emissions of existing CCGTs, but what is important is whether the full range of CCGTs can comply with the EPS. Since smaller generation plants tend to have higher emissions than large plants, and the full range of sizes, technologies (duct firing and dry cooling), and locations (affecting performance due to altitude and ambient temperature) may not be represented by the stock of existing plants, an emissions value of at least 1,100 pounds per MWh is more appropriate than the 1,000 pounds per MWh standard proposed in the Revised Staff Proposal. It is worth noting that of the many parties that filed post-workshop comments, all of whom examined the same data that forms the basis of the Revised Staff Report, not one proposed an EPS of less than 1,100 pounds per MWh for existing gas plants entering into new or renewed commitments.

SCE: SCE believes the standard of 1,000 lbs CO₂/MWh is too low and could eliminate a significant amount of generation resources from being eligible to be procured by IOUs and other LSEs on a long term basis. This number should be analyzed more fully in a workshop to discuss the redirection of this proceeding in light of SB 1368.

NRDC/TURN/UCS/WRA: We support the staff proposal, section 6.b to institute a single standard for all covered facilities, set at a limit of 1000 lbs CO₂/MWh. Data submitted by parties subsequent to the workshop confirms that all LSE-owned or contracted CCGTs with capacity factors of at least 60% in 2004 and 2005 have emissions rates that fell below the 1000 lbs/MWh threshold during that time period. However, we do not agree that the emissions standard should be set at a level "equal to a high-performing new CCGT" (section 6.a.i). Selecting an emissions performance level at the emissions of a high-performing CCGT is inconsistent with the staff's described methodology of evaluating the data response, which collected data on all existing facilities, not only high-performing CCGTs. Setting the standard at a level such that the emissions levels of

existing CCGTs would pass the screen is consistent with SB 1368, which states that “All combined-cycle natural gas power plants that are in operation...shall be deemed to be in compliance” with the EPS (Section 8341(d)(1)).

DRA: supports the proposed EPS limit of 1000 lbs of CO₂ produced per MWh of electricity delivered. This is considerably higher than that of the best available new CCGT plants. For example, an emission rate of 745 lbs of CO₂ /MWh is implied by the heat rate of 6,375 BTU/kWh used for the computation of the Market Price Referent in the Renewable Portfolio Standard proceeding. However, the proposed limit would still promote the use of more efficient technology, as compared with the higher limits proposed by some other parties. A lower limit will result in combined long-term savings in fuel use, fuel cost, and the avoidance of future carbon dioxide costs. Senate Bill 1368 is aimed at the same goal as the EPS proposed in the Draft Workshop Report, to set the EPS at the level of a combined cycle gas turbine. If SB 1368 becomes law, Section 8431(d)(1) would require the Commission to adopt an EPS "no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation." As the chart below shows, the range of acceptable EPS would be 800 to 990 lbs per MWh, or very close to the currently proposed 1000 lbs per MWh. DRA also notes that based on engineering calculations, power plants using dry cooling should be allowed a higher EPS in recognition of their countervailing benefits of lower water use. For example, a study commissioned by the California Energy Commission found that dry cooling would reduce the efficiency (and thus increase the production of CO₂) by about 1.5% in the Central Valley. The EPS adopted by the Commission should note the possibility of including this modification.

Sempra Global: agrees with the 1000 lbs CO₂/MWh standard and notes that newly enacted section 8341(d)(1) provides that all combined-cycle natural gas plants that are in operation or have a final permit decision to operate as of June 30, 2007 shall be deemed to be in compliance with the EPS. The 1000 lbs CO₂/MWh both satisfies section 8341(d)(1) sets a threshold for new generation that is consistent with the Commission’s articulated goals for the EPS, while encouraging load-serving entities to procure from the most efficient generating units.

EPUC/CAC: We initially proposed a standard of 1000 lbs/MWh if the standard was to be applied only to **new** facilities. The Staff Proposal, however, proposes to apply the standard to both new and existing facilities. For this purpose, and in light of workshop discussions, this value is too low and could exclude or distort the availability of important resources.

The data provided for Data Request #3 indicates that at least one existing combined cycle unit emitted at a rate above 1.0 lb/kWh (Workshop Report, page 28). Although this particular unit would be “deemed” to be in compliance under SB 1368, it indicates that basing the emission rate on new combined cycle technology can exclude some existing units. Moreover, because the data request responses did not examine the historical operation of power plants in years 2000 and 2001, which were low hydro, high fossil generation years, it is also likely that more than one existing, base-loaded gas-fired unit’s GHG emission rate exceeded 1.0 lb/kWh during those years.

Depending on the methodology used to incorporate a cogenerator's thermal energy into the calculation of an emission rate, some of EPUC/CAC's cogeneration facilities (constructed and contracted in the 1980s) may not meet a standard of 1.0 lb/kWhs. Cogeneration supplies 17% of the generating capacity in the state, and any EPS standard must preserve that existing fleet to ensure reliability. The Commission must also consider that as load grows, existing plants will be utilized to a greater extent, until new capacity is constructed. Their capacity factors will increase and more plants would be subject to the EPS. To ensure that no existing gas-fired plant is excluded, the EPS for existing resources should be set at a higher number, such as 1.4lbs/kWh. With the availability of existing plants safeguarded in this manner, a lower standard could be considered for new resources.

Constellation: does not object to the proposed 1000 lbs CO₂/kWh. However, To the extent that a different standard is proposed as a result of SB 1368, Constellation reserves the right to submit further comments in this proceeding.

GPI: We are pleased to see that the *Draft Workshop Report* adopts a single numerical standard for the interim EPS for all proposed procurements, whether based on new, repowered, or existing generating equipment. We are concerned, however, that the numerical standard that is selected is unnecessarily tight. The proposed value of 1,000 lb/MWh could exclude some legitimate CCGT generating facilities. In our opinion, this is not the purpose of the standard. The purpose of the standard is to avoid long-term commitments to generating resources with greenhouse gas emissions that are **higher** than the emissions from a natural gas-fired CCGT generator. The purpose of the EPS standard should not be to differentiate among different CCGT configurations, some of which might have higher heat rates in order to meet other (non-greenhouse gas) admirable environmental objectives, such as a facility with dry cooling technology for purposes of minimizing water use. As we stated in our *Post-Workshop Comments*, the interim EPS should be set at a level of 1,100 – 1,200 lbs/MWh, which will accommodate all of the kinds of generators that the rule is intended to permit, while excluding all of the types of generators that the rule is intended to avoid.

Calpine: supports the adoption of 1,000 lbs CO₂/MWh as an appropriate EPS limit, it believes the Commission can - and should - take additional steps to encourage long-term commitments with resources with emissions *below* the limit. For example, the Commission could establish incentives to reward load serving entities ("LSEs") for contracting with lower emitting resources and resource owners for developing lower emitting resources. Such an approach would not only help prevent "backsliding," it would serve to encourage the development of lower emitting resources which, in turn, will accelerate reductions in GHG emissions and move California closer to meeting its longer-term environmental go

CEED: Given the draft proposal limitations, the CEC Net System emission average for unspecified resource contracts would likely exceed the EPS limit. The CEC calculation would include older fossil fuel plants and plants using longer carbon chain fuels may be far above the 1,000 lb/MWh limit that would likewise yield a system average much

greater than 1,500 lb CO₂/MWh. In summary, the draft proposal, as written, would prohibit California utilities from signing any long-term unspecified resource contracts.

- b) Potential R&D exemption on a case-by-case basis for higher emitting facilities. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions¹⁷, and that has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement.

PG&E: supports an exemption for advanced coal or other GHG-reducing technologies to be considered and granted on a case-by-case basis.

NRDC/TURN/UCS/WRA: We strongly oppose any R&D exemption, even on a case-by-case basis. Because the Commission has selected a gateway standard, which we agree with, the mere assurance that an IGCC coal plant that “has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide” is not sufficient to ensure that it will in fact realize such a plan and reduce and maintain emissions at or below the EPS limit in the future. Though we believe that the Commission should support research, development, and deployment of advanced technologies, it must not do so at the expense of potentially undermining the EPS. There may be ways other than an outright exemption to address any timing challenges to actually capturing and sequestering the carbon from these plants, and we are open to exploring them. But there must be adequate assurance through strict performance guarantees that the carbon *will* be sequestered in a manner that conforms to the emissions limit prescribed by the EPS.

DRA: The Commission should closely monitor the construction of power plants that would rely on yet to be developed technology, including methods of carbon dioxide sequestration. If any such power plant is constructed, stringent standards and continued monitoring should be used for any such plant, to ensure that the carbon dioxide control strategy is actually implemented, and substantial penalties should be applied in the event of failure to do so.

PacifiCorp: supports the staff recommendation to include a research and development exemption that could be granted by the CPUC on a case-by-case basis for higher emitting facilities upon demonstration that the commitment in question will make a significant contribution to developing a lower-emitting resource mix in the future. The staff recommendation includes an example of “an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions, and that has or will have within a reasonable period of time the capacity and an existing plan to capture and store carbon dioxide.” We would comment that an IGCC facility itself, designed to be carbon capture ready, should automatically qualify for the research and

¹⁷ In the response to Data Request Q3, parties indicated an average heat rate of 8630 btu/kWh and emissions rate of 1770 lb CO₂/MWh for IGCC facilities.

development exemption until such time as they become the commercial standard in the western United States given that none are in operation today. The staff recommendation could include a presumptive threshold that the first five IGCC carbon capture ready facilities built within the Western Electricity Coordinating Council would automatically qualify for the exemption and any others that followed would be reviewed and approved on a case-by-case basis.

Sempra Global: supports the availability of a case-by-case exemption for promising technologies and notes that newly enacted section 8341(d)(5) already provides that carbon dioxide that is injected into “geological formations” so as to prevent its release into the atmosphere shall not be counted as power plant emissions. The Commission should apply appropriate safeguards and conditions such as time limits to ensure that any exemptions granted are not abused.

GPI: The key ambiguity here is: What constitutes a demonstration that the proposed project will make a significant contribution to developing a lower-emitting resource mix in the future? Is it sufficient for a proposed project to have a plan or does the project actually have to be **planning** to capture and store carbon? Any high-emitting power plant can produce a paper plan for carbon sequestration. If it is determined that building an IGCC coal-fired power plant makes a sufficient contribution towards the development of carbon sequestration to justify an exemption, then the interim EPS will be completely ineffective. As far as we can tell, neither of the recently passed bills on greenhouse gases, SB 1368 and AB 32, include any kind of R&D exemptions for high-emitting resources. AB 32 does have a section encouraging research and development into low emitting resources, but neither bill even hints at an R&D exemption, certainly not for the EPS (SB 1368). We urge the Commission to rethink its decision to offer an R&D exemption to the interim EPS for high-greenhouse gas emitting facilities. At the very least, the Commission should provide strong guidelines that require applicants to go well beyond simply producing a paper study describing a sequestration plan, and actually commit to performing real sequestration.

Calpine: opposes exemptions for resources that cannot meet the interim EPS limit, except in the limited case where a strong showing is made that a non-compliant resource is necessary for reliability purposes. Exemptions for reasons other than reliability purposes will undermine the effectiveness of the interim EPS. If advanced coal technology cannot meet the interim EPS limit absent carbon sequestration, then that resource should not be eligible for a long-term commitment with an LSE unless and until the sequestration process is operable and the resource can demonstrate compliance with the interim EPS limit. By the same token, if advanced coal (or any other technology) can meet the interim EPS, then the resource should be eligible for a long-term commitment.

IEPA: This proposal is not appropriate for what is intended to be an *interim* EPS and will serve to decrease transparency, provide opportunities for gaming, and increase administrative complexity.

CEED: [CPUC's goal of encouraging advanced technology] would be better achieved if some predefined R&D projects such as carbon capture ready [Integrated Gasification Combined Cycle ("IGCC")] projects and ultra-supercritical pulverized coal units that provide potentially low CO₂ options were automatically exempted from the EPS and not subject to an expensive or drawn out approval process.

7) Application of the standard to units and contracts

- a) Single unit specific contracts: contracted unit must qualify
- b) Multi-unit contracts: each covered unit must qualify
- c) Baseload renewable product with a firming fossil unit(s) that qualifies as a "covered resource": baseload blend average of all covered facilities (renewable and fossil). If firming unit is unspecified impute appropriate emissions factor.

PG&E: For contracts which are a blend of specific units or facilities, PG&E agrees with the Draft Report's recommendation to using the design heat rate and forecast capacity factor for each unit or facility, as information is available. However, with regard to a renewable contract firming with a non-renewable resource, PG&E disagrees with the Draft Report's "blending" requirements and continues to recommend that RPS-eligible resources be categorically deemed in compliance with the EPS, without regard to the characteristics of any firming non-renewable resource behind the RPS-eligible resource. It is PG&E's hope that 100% of the energy delivered through these contracts could be tied back to a renewable resource. The purpose of having the system or nonrenewable electricity as a back-up resource is to remove operational hurdles to completing new contracts with RPS-eligible resources. While PG&E believes that "firmed" renewable commitments would meet the EPS, PG&E advocates exempting these contracts to reduce administrative barriers for RPS-eligible resources.

NRDC/TURN/UCS/WRA: Blending of specified or imputed emissions of unspecified resources should **never** be allowed. Blending would act completely counter to the purpose of the EPS in reducing significant reliability and financial risks associated with high carbon-emitting resources by allowing the emissions of the high-carbon emitting resources to be "diluted" by a cleaner resource.

Thus, we strongly recommend that emissions blending of "baseload renewable products" (section 7c) NOT be allowed, whether the "firming" resource is specified or not. A contract that contains electricity from both non-renewable and renewable sources is a multi-unit contract and should be treated as such (section 7b of the staff proposal), where each covered unit must meet the EPS in order for the entire contract to qualify. An individual evaluation of each unit behind the contract is necessary to avoid the potential for renewable products in which renewable generators are "firmed" with carbon-intensive fossil generators.

In the case of a renewable product that is firming with an identified fossil unit/facility or units/facilities, we contend that each unit/facility which comprises the product should be subject to the EPS (again applying the EPS criteria to the underlying

unit/facilities), if the unit/facility is operated at an annualized capacity factor of 60% or greater. All indications at the workshop are that no utilities have ever purchased or have plans to purchase a renewable product in which the “firming” resource is a baseload resource, as a baseload resource would not be suited for firming. Thus, whatever resource in the contract that is used to firm the renewable would not even go to the gate.

In the case of a renewable product that is firmed with an unspecified resource, we agree with the staff proposal that the appropriate emissions factor for system power be imputed, consistent with the imputed emissions of all other unspecified resources.

However, we believe that the imputed emissions of system power should be the emissions level of a pulverized coal plant, as explained below. In addition, the system power used to firm a renewable product should be treated as a “unit” of a multi-unit contract, and each unit must pass the EPS in order for the full product to pass.

In any case, as we have argued, the EPS should apply to each individual resource behind a contract. Thus, in this situation, the renewables portion of the product is deemed to be in compliance with the EPS (consistent with our arguments above in section II.5), and the remaining resource should be evaluated to see if it goes to the gate, consistent with the application of the standard as we propose.

This approach is consistent with Staff’s proposal to apply the EPS to each individual unit that is part of a multi-unit contract (section 7b). However, we also note that the discussion section of the workshop report seems to contradict section 7b of the staff proposal: “staff recommends modifying the proposal to allow for facility/plant average” (p. 23). We recommend the Commission clarify its intentions regarding multi-unit contracts in section 7b of the staff proposal.

EPUC/CAC: Section b provides that in multi-unit contracts, each covered unit must qualify. There is a corollary to this rule. If a particular unit within a contract package does not meet the threshold criteria, it should not be included in the examination of emissions rate. Some facilities with multiple units may have one contract that provides, for example, for delivery of a peaking product from one identified unit and a baseload product from another unit. Such contracts should be subdivided and the unit providing each product assessed to determine whether it meets the baseload characteristic. The Staff Report should provide: *“Where one single contract provides for deliveries with different specifications from more than one specified unit, the baseload characteristic for each delivery shall be separately analyzed, and the emissions rate for each unit separately determined.”*

GPI: Typical wind generators have annual capacity factors in the range of 30 – 35 percent, well below the threshold level that governs application of the proposed interim EPS standard based on the definition of covered resources (60 percent in the straw proposal). As long as the proposed procurement of firmed renewable energy is for deliveries with an annual capacity factor below the threshold level, then the procurement is automatically exempt from the interim EPS. If the procurement will have an annual capacity factor that is above the threshold, then half of the energy deliveries or more under the procurement will be from the firming resource, and the procurement ought to be subject to application of the interim EPS standard. We believe that in this case the procurement should be judged as a whole (emissions of renewable and firming energy

combined on an annual-average basis), rather than applied to each generator separately, on the basis that the relative contributions of the two sources of power under the procurement (renewable and firming) are intrinsically linked.

- d) Null renewable power treated same as unspecified power. REC-covered power treated as renewable.

PG&E: PG&E agrees with the Draft Report's recommendation that all renewables be assigned an emissions factor of zero for purposes of compliance with the EPS.

NRDC/TURN/UCS/WRA: We recommend that the treatment of "null" power not be considered at this time, as the appropriate treatment will depend on how the REC market is set up in California, and how good the tracking system will be.

It is also unclear what is meant by the term "REC-covered power," since RECs, once unbundled from the underlying renewable-generated energy, are no longer attached to contracts with specific generating units. We recommend the Commission clarify this language. We assume that the term "REC-covered power" is meant to refer to electricity generated by the RPS-qualifying renewable facility from which the RECs originated. If this is true, we support Staff's proposal that the EPS treat such generation as renewable.

GPI: Null energy is produced from generating sources with greenhouse gas emissions much lower than the proposed EPS. On that basis, it should automatically pass the EPS, and thereby enable the production of the unbundled RECs. For purposes of the interim EPS, null energy should be given an automatic pass. For purposes of a load-based greenhouse gas cap, some kind of suitable treatment for null energy will have to be developed, because the null energy will not be able to claim the same renewable attributes that were stripped away when the REC was separated from the energy. That is a phase II issue, not a phase I issue.

- e) Unspecified resource contracts: apply CEC "Net System Power" average. This is the statewide system average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a CA utility, and is the most representative option reflecting CA LSE procurement activities. All LSEs would use the same average emissions factor, regardless of location in the state.

PG&E: Where system purchases can be attributed to a region, the emissions should be calculated based on a geographic average. Where purchases can not be attributed to a region, PG&E supports the use of the CEC's most current Net System Power annual calculation.

SDG&E/SoCalGas: Assessing power from unspecified resource contracts is unclear. SDG&E and SoCalGas support the new, refined methodology for calculation of the "Net System Power" proposed by the CEC in its May, 2006 Report and recommend

that the Commission adopt the new methodology and the resulting assigned GHG emissions. The decision as to the appropriate methodology has major significance; power from unspecified resource contracts will pass the EPS if the new CEC methodology described in the May, 2006 Report is applied, but will not pass under the older methodology

SCE: The CEC “Net System Power” average does not accurately reflect potential generation resources underlying unspecified resource contracts. No relationship exists between the leftover energy in the system used to calculate the Net System Power and unspecified purchase contracts. By its very definition, Net System Power is the CEC’s calculation that approximates the mix of “leftover” or unaccounted for energy in the system. However, energy contracts without an upfront specified source are common transactions in the energy market today. These transactions eventually result in energy being delivered to the system from specific sources, which generally become known to the buyer and to the California Independent System Operator (ISO) at the time of delivery, or from neighboring electrical systems. To consider these transactions as “unaccounted for energy” is inappropriate. Thus, the Revised Staff Proposal effectively compares apples to oranges. If the Commission does decide to use Net System Power to determine the carbon intensity for unspecified resource contracts then it should at least adopt a higher and more accommodative performance standard so as to not eliminate all long-term unspecified resource contracts from an IOU’s resource mix. The Commission should recognize that non-unit-specific contracts are an essential part of the hybrid market structure today and are critical in hedging the energy cost exposure to the IOUs’ ratepayers. The Commission should neither preclude non-unit-specific contracts from being an integral part of an IOU’s portfolio, nor create artificial and costly programs just for the sake of creating an illusion of due process.

NRDC/TURN/UCS/WRA: We are extremely concerned that applying the CEC “Net System Power” average emissions rate to unspecified resource contracts or system power (as staff proposes in section 7e, and which would be deemed to pass the EPS) would create perverse incentives for LSEs to enroll in these contracts for periods of 5 years or greater. In addition, we understood from the workshop that no LSE is currently planning to procure long-term contracts for system power, and thus see no reason for the CPUC to consider creating a significant new loophole. Although we agree with the staff report that “information about underlying resources [for unspecified contracts] would be difficult, if not impossible, to ascertain at the present time” (p. 26), that should not be a reason to automatically allow unspecified contracts to pass the EPS. Also, it is expected that tracking systems will improve their ability to provide more accurate accounting of emissions from unspecified resources over time.

The pitfall of relying on the CEC Net System Power average is that an averaged emissions rate provides no information or guidance on the critical distinctions between emissions from different types of generating units. Averaging lower and higher emitting sources invariably dilutes the emissions rates of the higher emitting sources, and provides a significant loophole for long-term unspecified resource contracts. NRDC appreciates Staff’s willingness to “monitor contracting patterns and behaviors to ensure they do not change for this reason,” (p. 31), but we believe this monitoring activity would increase

the administrative burden posed by the EPS, and is contrary to Staff's own stated goal of administrative simplicity and upfront compliance.

To prevent contract loopholes and relieve administrative burdens and complexity, we strongly recommend the Commission assign unspecified resource contracts the emissions level of a conventional pulverized coal generator. As far as we are aware, no LSE has plans to sign long-term contracts for unspecified resource power in the future. Therefore, we see no reason why assigning long-term unspecified resource contracts an emissions value deemed not to pass the EPS would place undue burden on the LSEs.

DRA: Of the four options proposed for valuing for "unspecified" resources, DRA generally supports the staff recommendation to use the CEC net system power calculation. However, the workshop did not delve into the implications of nuclear and large hydroelectric energy in the unspecified energy, both from within and imported into the State. Including this type of power within the Net System Power Average results in an average that appears lower in GHG emissions than would result if the number included only fossil fuel generation. A more fundamental issue acknowledged by the Draft Workshop report is the possibility "LSEs will be inclined to enter into unspecified contracts with high emitting resources in order to circumvent the EPS by having a possible lower emissions rate assigned to that resource." While it may be the case that such contracts currently represent "a small fraction of the incremental power supply," assigning a value to unspecified resources that complies with the EPS could operate as a strong incentive to execute contracts for unspecified resources. The Commission should therefore adopt DSP's recommendation to monitor contracting patterns and behavior to ensure they do not change in an effort to hide the use of dirty electricity

Sempra Global: believes that there should be few, if any, "unspecified" resources subject to the EPS. Other jurisdictions have developed specific resource tagging mechanisms such as the Generation Attribute Tracking System (GATS) used by the PJM Interconnection and the Generation Information System (GIS) used by the ISO New England to track generation attributes, including GHG emissions, of resources within their control areas. The California Energy Commission has under development the Western Renewable Energy Generation Information System (WREGIS) for purposes of tracking compliance with California's RPS statute. In Sempra Global's view, it is entirely feasible to implement a program that tracks the GHG emissions of all generating units, and that would enable power marketers and other sellers of unspecified resource contracts to impute a reasonable and accurate GHG emissions profile to their contracts. Over time, this should be the strategy pursued by the Commission to deal with emissions from any long-term unspecified resource contracts. The other approaches, including staff's preference for the Energy Commission's "Net System Power Average" still leaves the door open to leakage, contract shuffling and other gaming of the EPS.

Calpine: opposes the use of proxies for purposes of determining compliance with the interim EPS because, by definition, such proxies do not reflect the actual emissions from a resource. As a result, there is no way to determine whether a commitment with an unspecified resource is consistent with the Commission's goals in this proceeding or simply exacerbates the problems the Commission and the State are trying to address. Moreover, although long-term commitments with unspecified resources may currently

make-up only a small fraction of the incremental power supply, the use of a proxy that would assign a lower emissions level to a resource could encourage long-term commitments with resources that would otherwise not meet the interim EPS limit. The net effect is that long-term commitments with higher emitting resources may ultimately increase. Policies that potentially increase long-term commitments with high emitting resources are inconsistent with the State's long-term environmental goals and should be discouraged. Accordingly, Calpine recommends that the Draft Workshop Report be revised to require that all long-term commitments for baseload generation involve "specified resources" that can demonstrate compliance with the interim EPS.

- f) For either specified or unspecified commitments: as discussed above in 5)d.iii., a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration. Multiple contracts with the same supplier, likely resource, or known facility are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate "slicing and dicing" of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

NRDC/TURN/UCS/WRA: Sections 7f and 7g again refer to staff's proposal to monitor multiple contracts; please see our response to this issue in section II.5 of these comments. As we stated above, the CPUC can more efficiently prevent LSEs from engaging in such "slicing and dicing" of contracts by simply applying the EPS to the operation of the facility behind the contract rather than to the contract itself. Such an approach would help fulfill Staff's goal of administrative simplicity through upfront compliance, avoid the need for retrospective policing, and would be consistent with the direction of SB 1368.

- g) A series of related or similar contracts, regardless of size, that appear to "slice and dice" procurement commitments are not permitted to avoid the standards of the EPS. Related contracts must be considered together as a bulk contract. Multiple contracts with the same supplier, likely resource, or known facility, are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate "slicing and dicing" of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

8) Monitoring and Enforcement

- a) CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

PG&E: Compliance would be demonstrated up front through documentation of the facilities full load heat rate and expected capacity factor.

NRDC/TURN/UCS/WRA: We strongly support gateway, upfront review for the EPS, with “approval required prior to finalizing contract or commitment to construct” (section 8a), without any form of ongoing enforcement. Although staff does not have a specific recommendation at this time for what sources of documentation should be required, we support their recommendation to use “independently verified emissions data” (p. 33). We also recommend that the Commission add to the list of suggested sources of information the sources listed in SB 1368, Section 8341(b)(4)

ESPs operate fundamentally differently from the IOUs. Their procurement plans and transactions are not subject to the requirements of AB 57, therefore EPS compliance monitoring for ESPs must be conducted differently than that for the IOUs. The Revised Staff Proposal appears to present conflicting statements with respect to how ESP compliance with the EPS will be determined. EPS monitoring and compliance fails to reflect important distinctions between ESP and IOU compliance.

Constellation: In its post workshop comments, Constellation recommended the following: To the extent that an ESP’s procurement would trigger the interim standards, we believe that compliance showings can be primarily made through modification to the existing RAR compliance mechanisms, rather than trying to alter the existing IOU AB 57 procurement process. Specifically, ESPs should not be required to submit any procurement contracts for pre-approval. Under the AB 57 mechanisms, IOUs can receive pre-approval that provides them with certainty of cost recovery. The CPUC does not oversee ESPs ratemaking and the AB 57 mechanisms, including pre-approval, are not applicable to ESPs. Instead, the ESP can make a verified demonstration to the CPUC in the context of the existing RAR showing process either when the EPS threshold is triggered or on an annual basis to the CPUC to acknowledge that no trigger event occurred. The ESP could be subject to an independent third-party audit if the CPUC has any doubt that the ESPs are forthcoming in their demonstrations. At a minimum, the CPUC can require the LSEs to affirmatively state, once a year, whether or not they have purchased any such contracts over the course of the previous year. Constellation requests that the Workshop Report and Revised Staff Proposal be modified in accordance with these recommendations on ESP compliance monitoring. Constellation would note separate treatment for ESPs with respect to review of contracts that trigger the gateway screen is expressly permitted in the recently passed SB 1368 legislation. Setting aside that the IOU AB 57 procurement processes do not apply to ESPs, a contract review process that would require ESPs to submit their contracts for pre-approval would create a *de facto* and commercially thorny requirement that ESPs require their contractual counterparty suppliers to hold open their offers for some unknown period pending a pre-approval process. Any requirement that would delay commercial commitments will potentially reduce the number of counterparties willing to transact with ESPs and/or

result in a sizeable price premium to reflect the risk the supplier faces in holding open a contract while market prices may move rapidly and markedly. For these practical, commercial reasons, in addition to the fact that the AB 57 procurement process is not applicable to ESPs, there should be no requirement under the EPS that ESPs seek Commission pre-approval of covered contracts. Instead, Constellation suggests that ESPs address whether or not they secured capacity or energy from covered contracts within the regular compliance filings made annually and monthly in the resource adequacy effort. Such an approach would provide a simple, administratively efficient and timely means of informing the Commission of EPS compliance.

AReM: proposes that rather than requiring ESPs to submit their contracts to the Commission for pre-approval, ESPs would make an annual showing of compliance with the interim EPS as an addendum to their year-ahead resource adequacy compliance filings. In most cases, an ESP would simply certify that it had not entered into any contracts during the previous year that are subject to the EPS. If an ESP entered into a contract that is covered by the EPS, it would provide the Commission with a summary of such contract information as would be necessary to verify that the contract is in compliance with (or exempt from) the procurement standard. Importantly, AReM's proposal is consistent with SB 1368. While this legislation expressly requires the IOUs to submit proposed contracts to the Commission for pre-approval, it does *not* require non-IOU LSEs (e.g., ESPs and CCAs) to do so. Since the Legislature could have directed the Commission to apply the same requirement to ESPs but chose not to do so, it is reasonable to conclude that the Legislature concluded it was not necessary or appropriate to require ESPs submit their contracts to the Commission for pre-approval under the EPS. Change language to: "Require ESPs to demonstrate compliance or exemption but not submit contracts for preapproval."

9) Offsets, Safety Valves, and other flexibility devices

a) No offsets or market price safety valves

SDG&E and SoCalGas: believe that some type of price "safety valve" should be included as part of the EPS for the protection of utility customers and to ensure consistency with SB 1368

SCE: Exemptions should not be limited to reliability. Exemptions should also be considered on a case-by-case basis for significant economic impacts caused by applying the EPS. Thus, Section 5(h) does not go far enough. SB 1368 adopts PUC Code section 8341(d)(6), which should form the basis of an exemption to the performance standard.

NRDC/TURN/UCS/WRA: We strongly support staff's proposal for no offsets or market price safety valves. The primary reason for disallowing these flexibility devices is not just that they would require "significant up front analysis and ongoing monitoring" (p.32), but also that they would defeat the purpose of having standard by simply providing a way to get around it and not comply.

Sempra Global: observes that AB 32 contains the following provision for the state's GHG emissions reduction program in newly enacted Health and Safety Code section 38599:

(a) In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline.

(b) The adjustment period may not exceed one year unless the Governor makes an additional adjustment pursuant to subdivision (a'). A parallel provision in the EPS would be appropriate -perhaps one that allows an individual load-serving entity to request an exemption from the EPS not just for reliability reason, but in the event of extraordinary circumstances, catastrophic events or the threat of significant economic harm. As an additional example, the northeastern Regional Greenhouse Gas Initiative draft final rules provide for a liberalization of the criteria used to determine whether and what kinds of offsets may be used by emissions sources when the price of allowances exceeds \$7 per ton of carbon-dioxide equivalents. Similar rules should be considered in California's EPS in the event that specific kinds of resources are required for economic or operational reasons.

IEPA: resources may operate differently than expected at the outset of the commitment due to changes in system efficiencies or locational issues that may arise through time, among other factors. Therefore, any generation source's compliance with the EPS should be measured at the outset of the commitment and be based on expected operations at that time.

b) Case-by-case exemption for reliability only considered upon application and CPUC review.

AReM: The word "application" denotes the contract pre-approval process contemplated for the IOUs, and not a more streamlined process as workshop participants recognized would be appropriate for ESPs. So as to incorporate the latter into the straw proposal, AReM recommends that the word "request" be substituted for "application" in Section 9.b.

Additional issues addressed by parties:

Constellation: Assembly Bill 32 and Senate Bill 1368 were recently passed in the State Legislature. Constellation believes that both of these bills present few, if any, conflicts with development of the EPS as currently underway in this proceeding. Presumably, Commission Staff is reviewing these measures to ascertain whether either of them (should they be signed into law by Governor Schwarzenegger) necessitates changes to the Workshop Report or Revised Staff Proposal. If a determination is made that certain modifications are warranted, Constellation respectfully requests that parties be provided an opportunity to comment on any revisions.

SFCP: The interim EPS, as currently proposed, will create a perverse incentive when rolled into a succeeding cap-and-trade program adopted by the Commission. For example, a natural gas plant would receive an allocation of significant value because it has emissions while a wind plant receives no allocation since its expected emissions are zero. Therefore, the interim EPS can create an incentive to invest in a new combined cycle plant that emits at the EPS rate over a zero-emitting wind plant in the context of a transition to a market-based mechanism program such as cap-and-trade. Of course, this is counter to the overall intended policy objective of the GHG OIR.

Another study of the EU ETS new entrant provisions, which are similar to the interim EPS reveals a distortion in resource allocation that is likely to lead to overinvestment in production capacity.¹⁸ This will tend to reduce the constraint on the GHG credit market, reducing the apparent compliance cost, but that cost is simply hidden in too much generation investment. As a result, the overall social costs will increase along with the total emissions.

The most important findings from these studies is that any emissions created from resource acquisition under the interim EPS must not be included in the baseline allowances allocated to LSEs when a market-based mechanism is adopted. ***In essence, the Commission should adopt a policy that imposes a date-certain liability for all emissions that is in place before any further significant resource acquisition occurs.*** This can be done by stating a specific date, e.g. January 1, 2007, that will be used for calculated emission allowances at some future date. In this way, LSEs will have an incentive to adopt the most-efficient, least-emitting resources because any additional reductions beyond the EPS will have value at a future date under a trading scheme.

Carson Hydro Project: The Commission should adopt this SB1368 provision as a part of its final EPS regulation.

Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard.

Carson Hydro Project: State's new policy of encouraging the development of "zero- or low-carbon generating resources," suggests a need for further consideration in the procurement context. Policies to encourage this category of resources could be addressed in the 2007 Long Term Procurement Plan proceeding and/or the Energy Action Plan review. For example, the Commission should consider placement of these generating resources in its existing load order. CH2P thus requests that the Commission direct parties to address these new issues arising from SB 1368 in a designated forum.

CEED: By eliminating all cost containment provisions from the EPS, and in failing to address the costs to ratepayers, the Draft Report neglects its obligation to protect ratepayers from the costs of the EPS. To provide the flexibility needed to be "efficient

¹⁸ A. Denny Ellerman, "New Entrant and Closure Provisions: How do they distort?" *Energy Journal*, Forthcoming (2006).

and cost effective,” AB 32 authorizes use of “alternative compliance mechanisms” that allow offsets to provide for an equivalent reduction in greenhouse gases. AB 32 also permits the state to establish a GHG cap & trade system. *At the minimum, the commission should follow the governor’s and legislature’s lead on cost containment measures and permit offsets and portfolio averaging. The proposal should also establish carbon price caps to protect the California ratepayer.*

Emission offsets: This cost containment measure would ensure the reduction targets are met in a cost-effective manner, while expanding supplier competition. The Draft Report currently prohibits such use of offsets.

Portfolio averaging: Portfolio averaging controls costs by averaging emissions across multiple diverse facilities to comply with the environmental performance standard. Overall, there would be no net emission change to the environment while allowing the suppliers flexibility to offer a lower-priced product.

Price caps: The only true method to protect the ratepayer would be to establish a price cap for CO2 emissions. This approach is commonly applied in state renewable portfolio standards when they set a maximum price premium. The Draft Report should address how much California ratepayers should be willing to pay to avoid CO2 emissions and that would not adversely affect the state economy. To assure that this price is not exceeded, the Commission should set a price cap at or below this level.

Small Service Exemptions: As an additional cost containment provision, the Draft Report should include an exemption for utilities with small service territories in California. As S.B. 1368 provides, “[a]n electrical corporation that provides electric service to 75,000 or fewer retail end-use customers in California may file with the commission a proposal for alternative compliance with this section”

Appendix B

(Note: Names and contact info subject to typos due to the handwritten nature of the sign-in sheets).

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Appendix C

May 31, 2006

To: All Parties in R.06-04-090

From: Division of Strategic Planning

**RE: Direction for Workshops on the Interim Greenhouse Gas Emissions
Performance Standard for Electric Resource Procurement**

As discussed at the May 10, 2006 prehearing conference (PHC) in this rulemaking, Phase 1 will focus on the policy, design and implementation issues associated with an interim greenhouse gas (GHG) emissions performance standard (EPS) intended to serve as a near-term bridge to the load-based GHG cap adopted by the Commission in Decision 06-02-032.¹⁹ A set of workshops to develop the record and the understanding needed to craft an appropriate EPS will be held on June 21-23, 2006.

This memorandum provides guidance to the parties on the structure of the workshops and the issues to be addressed at them. Pre-workshop comments are invited on both the structure of the workshops and the substantive issues raised. Pre-workshop comments must be filed and served by the close of business on June 12, 2006. They are to be served electronically to the service list pursuant to the Electronic Service Protocols attached to the Order Instituting Rulemaking (OIR) and consistent with Rules 2.3 and 2.3.1. As directed in those protocols, hard copies are also to be served on Administrative Law Judge (ALJ) Gottstein and the Assigned Commissioner.

I. Overview

The starting point for analysis at the workshops will be the EPS set out by the Commission in its 2005 GHG Policy Statement. However, the language of the OIR does not limit our review to that particular design; thus the workshops will examine other leading options and modifications. Three days of workshops are scheduled. We anticipate that Day 1 will focus on overall policy questions, while Days 2 and 3 will address design options, implementation details and data needs.

II. Workshop Day 1

The first day of the workshops will focus on the basic policy questions underlying the proposed interim EPS. We will begin with a short review of the basic relevant data: As a general matter, what new procurement needs are load-serving entities (LSEs) anticipating filling in the next three to five years, and what fraction of those needs would be affected by an EPS that requires new procured resources to have a GHG profile no higher than that of a combined cycle gas turbine (CCGT).

¹⁹ We use the single acronym "EPS" throughout this memorandum to refer generically to a GHG emissions performance standard.

Each investor-owned utility (IOU) LSE should be prepared to provide such a short overview at the beginning of the first workshop. In answering this question, LSEs should consider a range of possible interim EPS rules, from one covering all new MWhs from all sources, to one covering only the largest, most long-term procurements. The workshops do not require detailed studies or resource plans from LSEs; where plans are uncertain, scenarios can be presented as options. Other respondents with information or projections concerning the possible application of the EPS to other LSEs will also be invited to present those projections.

With this basic information in hand, the workshop will consider four questions:

1. Should the Commission adopt an interim EPS to guide ongoing electric procurement decisions while it takes the necessary steps to fully implement D.06-02-032? Why or why not? Address the following in your response:

- a. What are the likely costs and benefits of imposing a performance standard on LSEs and their customers?
- b. Would failure to adopt a performance standard create unwise incentives to some LSEs and customers to “lock in” higher emission resources before an anticipated cap-and-trade system is imposed?
- c. How sharply do EPS costs and benefits vary with the type of performance standard imposed? With different assumptions about the future cost of carbon compliance?
- d. How do the performance standard and cap proposed by the CPUC interact with proposed state legislation in this area? How might potential legislation affect CPUC action in this proceeding?
- e. How would an interim EPS interact with the LSEs’ other responsibilities under the Commissions procurement orders?
- f. If the main purpose of the EPS is to forestall “backsliding” pending adoption of a load-side cap, are there other policies that could have the same effect in a more direct or simpler fashion?

2. If an interim EPS is adopted, to which LSEs should it apply? Why or why not?
²⁰ Address the following in your response:

- a. Should the standard apply solely to IOUs, or should it apply to all non-municipal LSEs within the Commission’s jurisdiction (including ESPs and CCAs)?
- b. Should the CPUC implement an EPS for LSEs within its jurisdiction while leaving the possible inclusion of public power entities to the Legislature? Would this result in major undesirable impacts on competitive markets, power flows, or system reliability and if so, how might those impacts be mitigated?

²⁰ Discussion on this topic during pre-workshop comments and at the workshop will focus on policy issues, not legal issues. As discussed at the PHC, there will be a separate opportunity for briefs on Commission jurisdiction with respect to the adoption of an interim performance standard to non-IOU LSEs.

3. Over what time frame should the interim EPS be implemented?

- a. As a practical matter, how soon could an EPS be implemented?
- b. Are any significant procurement decisions now pending or soon anticipated that ought to be covered by a new EPS policy?
- c. How long should the interim EPS be kept in place?

III. Workshop Days 2 and 3

The workshops on June 22 and June 23 will need to proceed under the design assumption that the Commission will elect to adopt an EPS to guide power procurement decisions, at least until an effective load-side cap is fully implemented. Here we will examine how such an interim EPS should be designed and implemented so that it could be put in place quickly to serve this purpose.

Initial summary of EPS options.

The second workshop will begin with a brief overview of the basic options for the EPS. These workshops will address the following topics:

4. To which power sources should an EPS apply?

The EPS under discussion in this proceeding focuses on incremental procurement actions, particularly to avoid “backsliding” in those investments and procurement decisions by jurisdictional LSEs. This focus raises several questions to be addressed in your pre-workshop comments and in the workshop discussion. Please be as specific as possible as to your proposed design, should the Commission elect to adopt an interim EPS:

- a. Should the EPS apply to *all* incremental purchases, contracts and/or units, or to a subset of them? If a subset is appropriate, should it be defined in terms of:
 - Size of unit or contract (e.g., MW capacity or MWh supplied)?
 - Length of contract?
 - Generation type (e.g., baseload versus peaker)?
 - Other definition of subset?
 - Some combination of the above?
- b. The Commission’s policy statement suggests applying the EPS only to commitments greater than five years in length; is this the right threshold for “long-term” commitments? Would three years be more appropriate? Does a shorter term just create greater incentives for short-term contracting?

- c. Should the standard apply to LSE purchases from Qualifying Facility ("QF") contracts and Distributed Generation ("DG") contracts?
- d. Should the standard apply only to LSE contracts and purchases, or to LSE's own new units? Should it apply to repowering existing units?

5. What is the standard, and how is it determined?

In its October 6, 2005 GHG Policy Statement, the Commission anticipated a performance standard for new procurement that would be set at the emissions level of a CCGT. Workshop participants will need to address how such a standard would be defined, and may also propose an alternative standard as long as one could be implemented in the near-term. In considering this issue, please respond to the following specific questions:

- a. Is the CCGT standard the right standard to use, or is there an alternative standard that would be more appropriate *and* that could be put in place quickly for an interim EPS?
- b. If a CCGT standard is used, will it be based on expected performance of a modern CCGT newly placed in service, or a CCGT at the end of its useful life (since performance degrades over time), or an average of emissions from existing CCGTs?
- c. How will this standard be measured--based on the emissions from a gas turbine only or from the entire CCGT facility?
- d. If peaking facilities are measured against the standard, would the standard be based on the heat rate of the duct firing of a CCGT or the start up of the CCGT? If the latter, what would be the assumed duration of operation?
- e. If the EPS is applied only to baseload units or contracts, will the standard be based on the CCGT facility heat rate or will emissions from start ups be considered?
- f. What other factors or options should be considered in defining a CCGT (or other) standard?

6. Applying the standard to covered resources

Once a standard is defined, compliance must be calculated by comparing the emissions from covered resources to it. This requires measuring emissions from covered resources, or assigning attributes to them. Address the following questions in your discussion of these issues:

- a. How should purchased power contracts, especially those from systems outside California, be treated? The Commission has in other contexts identified "contract shuffling" as a potential problem in assigning emission characteristics to power purchased by California LSEs. Can purchases from other power systems be treated on a unit-identified basis, or must system attributes be assigned?

- b. If generation associated with combined heat and power is included in the program, how is the thermal side of the combined heat and power operation accounted for? In implementing the standard, should the Commission adopt an assumed efficiency for the stand alone thermal application, or will case-by-case review be needed?
- c. Will the emissions from covered resources be treated on an immediate facility basis, or on a life-cycle basis, compared with life-cycle emissions from a CCGT?
- d. Should the EPS apply to each and every resource added to an LSE's power portfolio, or can the LSE average across new resources? That is, would it be appropriate to allow some "fleet averaging" across an LSE's separate (incremental) units or contracts? In considering this issue, discuss how your position would or would not:
 - Be consistent with the treatment of single power-purchase contract that are backed by multiple units;
 - Skew power contracting decisions.
- e. If LSEs *are* permitted to average across their new resources, should renewables that meet RPS requirements be included in the average? What effect would this have on the ability of California LSEs to purchase new coal-generated power?

7. Monitoring and enforcement

- a. What role should the CCAR play in collecting information on source emissions and monitoring compliance with the EPS Rule?
- b. If a GHG performance standard is adopted, how will compliance be measured if procurement decisions are made before mandatory CCAR registration? Based on heat rate and fuel type?
- c. What documentation will be required to demonstrate compliance?
- d. If combined heat and power QFs and DG are included, what type of documentation of the use of thermal energy is required?
- e. If a jurisdictional LSE does not satisfy the EPS with respect to a covered resource, should financial penalties, other remedies or both, be employed?

8. Offsets, Safety Valves, and other flexibility devices

Some participants have requested that any EPS Rule contain flexibility devices, potentially including offsets. There is also some interest in "safety valves" that would relax the program if its impact on power prices was too great, or it was seen to impose system reliability risks. In considering these and other related issues, provide a response to the following:

- a. What are the pros and cons of permitting offsets for an interim program of this nature?

- b. If you believe that offsets should be permitted, be specific with regard to the nature of allowable offsets and associated implementation steps (including timeline) to put an offset system in place.
- c. Given the EPS focus on new acquisitions, how can the Commission address the potential undesirable incentive for LSEs to extend the operation of existing, higher-emitting resources? Should LSEs be offered the equivalent of credits against replacement power sources²¹ if high-emitting resources are retired during the period of the performance standard? Are there other approaches that the Commission might consider to address this issue?
- d. Considering the scope of the EPS rule, and the basic information provided by LSEs about its reach, are safety valves of any kind needed? Is a “reliability override” needed, and if so, how should it be defined and administered?

9. Other Issues

- How would an interim EPS adopted in this proceeding be coordinated with the utility planning procedures and requirements emerging from the current procurement docket?

IV. Workshop Structure

At the three day workshop, we will work through the questions presented in sequence. *All workshop participants are expected to file pre-workshop comments addressing the issues/questions presented above.* As each topic is raised, we will present an overview of the pre-workshop comments on that topic. We will focus on general group discussion to clarify the range of views concerning the pros and cons/options under each of the topic areas, rather than spend time reiterating or further clarifying each individual participant’s positions. The discussion will be structured to assist us in identifying the leading options on each point, and where possible, to uncover points of consensus. Areas of disagreement will also be noted. The workshops will identify as much common ground among participants as possible, but we will not defer action on later items in order to find consensus on earlier points. Time permitting, the group will return to discussion of unsettled topics after working through the full list.

In addressing the Day 1 questions, respondents and interested parties should present their best assessment at this time of the costs, benefits and co-benefits (e.g., job-creation, economic impacts) associated with the establishment of an interim GHG emissions performance standard. Throughout Days 2 and 3, the parties should keep in mind the focus of this phase on an interim or “bridge” performance standard that can be put in place quickly. As discussed at the PHC, the utilities and interested parties are

²¹ This would be similar to the application of “early reduction credits” in other pollution management regimes.

expected to ensure that their technical and policy experts on these issues attend the Phase 1 workshop, so that there can be a productive dialog on these matters.

Data issues:

The purpose of these workshops is to identify the pros and cons of different approaches to an interim EPS to guide the Commission's eventual decision in Phase 1. As discussed at the PHC, a Commission determination in Phase 1 will benefit from an analysis of basic information on procurement options but will not require extensive data collection or economic modeling. Accordingly, some basic data will be needed to guide discussion and to consider some of the EPS's benefits and costs, but these workshops are not intended to develop extensive studies or power cost models for this purpose. As noted above, each IOU respondent is required to provide a brief overview of its resource procurement needs on Day 1.

For this purpose, as suggested at the PHC, the utilities and interested parties discussed data needs at a May 22, 2006 conference call. Following up that meeting, the Division of Strategic Planning has directed, in consultation with ALJ Gottstein, that the respondent IOUs serve the following information electronically to the service list by close of business on Wednesday, June 7, 2006:

Q 1 What percentage of current contracts is "dirtier" than CCGT? What percentage of currently owned generation is "dirtier" than CCGT?

Q 2 What percentage of contracts is not tied to specific units? How many MWs and MW-hrs do these contracts represent?

Q 3 How many contracts and how many MW-hrs are equal to or less than three years in length? Equal to or less than five years in length?

Q 4 How many MW/MW-hrs are you planning to procure (add, renew, or turn over) in the next three to five years, and what are your anticipated resource additions (and which kinds of resources) at this point in time? What are the cost and reliability impacts, and benefits and co-benefits, of migrating these resources to those as clean as or cleaner than CCGT?

Q 5 What are the cost and reliability impacts, and benefits and co-benefits, of migrating 10% of your current portfolio? Of migrating 20%?

In presenting this information, the IOUs should include all sources and assumptions underlying their responses to this data request. The IOUs are expected to prepare a short presentation of this material on Day 1 of the workshop, with hard copy

handouts to the workshop participants.²² They will need to coordinate with the workshop facilitator (see below) ahead of time with respect to the handouts, time allotted for presentation, etc.

Workshop participants who intend to provide additional information to guide the workshop discussion should submit them with their pre-workshop comments on June 12, 2006, together with all underlying data sources and assumptions.

Workshop leaders:

These workshops will be led by Richard Cowart of the Regulatory Assistance Project (RAP) with assistance from Lainie Motamedi from the Division of Strategic Planning. ALJ Gottstein will also be in attendance. Participants are invited to contact Mr. Cowart directly with workshop questions and suggestions at RAPCowart@aol.com, or 802-223-8199.

Agenda and Presentations:

Suggested modifications to the questions presented above, or to their order of discussion should be filed with parties' pre-workshop comments by June 12. Those who wish to schedule presentations to the group on one or more of the topics above should contact Richard Cowart. He will consider those requests and finalize the agenda in consultation with ALJ Gottstein and the Division of Strategic Planning.

²² They may also make further refinements to the June 7 submittal for this purpose. If further refinements in the June 7 responses are made, the IOUs should clearly present in their workshop hand-outs the nature of the refinements, along with any updated data or source information.

Appendix D

The cogeneration calculation presented by Energy Producers and Users Coalition and Cogeneration Association of California at the June 21-23, 2006 Workshop is posted at:
www.cpuc.ca.gov/static/energy/electric/climate+change/cogen+calculationpresentation.pps

Appendix E

Data Requested at the June 21-23 Workshop

Note: Responses to the Data Request are posted at www.cpuc.ca.gov/static/hottopics/1energy/r0404003.htm

At the workshop, the IOUs (PG&E, SDG&E, SCE) and other workshop participants agreed to prepare the information/analysis on topics related to the threshold policy issue and implementation design considerations for an interim EPS, as follows:

1. The size of the potential IOU procurement needs that would be covered by an interim EPS. The IOUs and the CEC are working on a common format for this information and will be providing the format to staff by July 7. By July 11, both redacted (public) and unredacted versions of this information will be provided to staff. The intent is to provide to the service list as much publicly available data on this topic as possible.
2. Analysis around the definition of "covered resources:" What proportion of GHG emissions from long-term commitments would be excluded/included if the threshold for review is 60% average annual capacity factor vs. 50%, 70% or 80%? The IOUs will be providing this information to staff by July 11th.
3. Graph/Schematic of representative heat rates/emission rates for different types of facilities, for the purpose of considering the level of the "moderate" and "high" EPS thresholds for existing/new facilities under the staff Straw Proposal, or alternative approaches. The IOUs and other workshop participants agreed to coordinate on this document, due July 11 to staff.
4. Size of potential ESP procurement. SCE and AReM are working on this information that will be submitted to staff by July 14.
5. Emission factors for unspecified resources. CEC staff will provide the WECC regional emissions average, sub-region averages and the "net system" average figures to staff by July 11.
6. Potential new sources of power (new projects coming on line) proposed for potential sale to California IOUs. CEC, WRA, Constellation and PacifiCorp agreed to pull together the data available on this issue, and provide it to staff by July 11.

In addition, at the workshop several participants agreed to coordinate the development of the following information to present in their post-workshop comments (jointly, if possible):

- a. How one would calculate the net emissions rates from renewables (GPI, PG&E, NRDC and others)
- b. The formula for a cogeneration thermal credit calculation, and whether it is consistent with the CARB approach: (EPUC circulating to others before comments are due)
- c. Protocol for assigning "covered resources" to California for multi-jurisdictional utilities and other implementation issues unique to multi-jurisdictional LSEs (PacifiCorp, WRA).

Staff intends to serve the information listed under 1-6 above to the service list upon receipt, so that you will have it as soon as possible to consider for your post-workshop comments. If you are interested in participating in the development of this information, please contact the parties listed above as soon as possible. The service list with contact information is accessible at www.cpuc.ca.gov. In addition, you can contact Lainie Motamedi (415 703-1764) or Carla Peterman (415-703-1112) in our Strategic Planning Division for questions or further information about these submittals.

Thank you,

ALJ Meg Gottstein

Appendix F

Request for Participant Comments on the Revised Workshop Report

As indicated in the June 1, 2006 Ruling setting the Phase 1 schedule, opening comments on this Workshop Report are due September 1, 2006 with reply comments due September 12, 2006. Please discuss your views on the updated staff proposal, and support your arguments with specific examples where possible. To the extent possible, include your evaluation of costs and benefits associated with the proposed program and with any modifications that you may propose. Please note that it is not necessary to repeat comments or previous arguments submitted in this phase of the proceeding.

Appendix G

DIRECTIONS FOR PHASE 1 POST-WORKSHOP COMMENTS

Note: We include this information as some parties submitted their comments on the Draft Workshop Report in this format.

We are soliciting post-workshop comments in order to further develop the record on the policy and implementation issues associated with the Commission's consideration of an interim GHG emissions performance standard (or "EPS"). The post-workshop comments may also respond to the arguments made by parties in pre-workshop comments. However, the focus of the post-workshop comments should be to further elaborate on specific areas of discussion at the workshop, including the following:

A. Threshold Issue: Should the Commission adopt an interim EPS?

1. If you are in support of an interim EPS, describe the advantages of adopting one. If you recommend that the Commission *not* adopt an interim EPS, present opposing arguments on this issue. ***Please initially respond to this question in the context of the "gateway" EPS described in Appendix A (Staff Straw Proposal). If your response would differ based on an alternative EPS design, please so indicate.***
2. In the context of your answer to #1 above, address whether an EPS serves to address the Commission's goals for procurement differently/better than current procurement policies, such as the current GHG adder. If the GHG adder were significantly increased, would this obviate the need for an EPS, in your view, why or why not? In your response, describe the current purpose and application of a GHG adder relative to an EPS.

B. Implementation/Design:

3. Assuming that the Commission decides to proceed with an interim EPS, what should be the major design principles/objectives for such a standard? Please identify what you consider to be the ***top four priorities*** for design criteria, and why. The following is an illustrative list developed from the workshop discussion, but others may be presented and discussed.

The EPS should:

- Be designed to prevent major "backsliding" (and if you choose this design objective, please clearly define your use of the term "backsliding");
- Be workable and administratively as simple as possible.
- Address reliability concerns, e.g., be designed to prevent the shutdown of essential facilities;
- Signal development away from high-emitting resources;
- Encourage (as well as not hinder) advanced technology development;
- Minimize costs to ratepayers;

- Minimize the risk of long-term commitments that will raise future compliance costs;
- Other?

4. The first major fork-in-the-road design issue discussed at the workshop was whether the EPS should be a “gateway” threshold versus a standard that applies to the ongoing operation of a facility (built or under contract). The general consensus of workshop participants was that an interim EPS should be a gateway standard that is applied when the load-serving entity (LSE) seeks approval for construction or purchase commitments, based on documentation concerning the expected resource/facility operating characteristics and associated GHG emissions.

Please discuss the relative advantages of this approach, and the potential disadvantages. If you believe that the EPS should in fact be applied in a different manner, please describe your proposed approach and the relative advantages/disadvantages of your proposal. Relate your response to this question to the design priorities you articulate under Question #3 above.

5. Another fork-in-the-road design issue discussed at the workshops was the application of an EPS to new generation resources as well as to renewal or new contracts with existing facilities. The Staff Straw Proposal applies the EPS to new **commitments** (construction, new or renewal contracts) for both. (See Appendix A.) Please comment on whether you support the Staff Straw Proposal on this issue, indicating your views on the relative advantages and disadvantages of applying the EPS to both new and existing generation facilities (under new commitments). Relate your response to this question to the design priorities you articulate under question #3 above.

6. There was also general agreement among workshop participants that if adopted, an interim EPS should cover commitments (construction or contracts) five years or longer, which is also reflected in the Staff Straw Proposal. Do you agree? Why or why not? How does this design parameter achieve (or not achieve) the priorities you have identified under question #3 above?

7. Another major design issue discussed at workshops was what the Commission should look at (contract or facility operation) in determining whether the EPS applies. In particular, should the Commission (1) look at the operation of the facility underlying a contract²³, or (2) only to the amount/product contracted for by the LSE? The Staff Straw Proposal takes the approach that, for specified contracts, the Commission should look at the expected operation and emissions of the facility, rather than just the contracted amount.²⁴ Please comment on the advantages and disadvantages of these two alternative approaches, and your position on this issue.

²³ Or in the case of joint ownership of a power plant, the entire facility being constructed.

²⁴ As indicated in Appendix A, under the Straw Proposal the Commission would impute an emissions profile for unspecified contracts.

8. There was general agreement during the workshop that an interim EPS should *not* apply to peaking facilities or resources expected to operate relatively few hours during the year. Accordingly, the Staff Straw Proposal uses a definition for “covered resources” as those with an annual average capacity factor of 60% or greater, intending to cover resources operating as year-round base load and high-use intermediate and shaping facilities. Do you believe that this definition of covered resources is appropriate? In responding, please address the following:

- a. What types of resources do you believe the EPS should cover and whether you believe the straw proposal capacity factor (60% or greater) metric to define a covered resource will capture those resources.
- b. Present an alternative metric(s) for defining “covered resources” that you recommend, if you do not support the Staff Straw Proposal definition.
- c. Whether (and if so, how) the EPS should incorporate a research and development exemption for advanced coal or other technologies.

9. Another design issue discussed at the workshop was how the EPS should apply to specified contracts with more than one underlying covered resource (new or existing): Should the Commission apply the EPS to the “blend” of the resources/units, or require that each covered resource meet the EPS individually?

Under the Staff Straw Proposal, each individual covered resource must meet the EPS, with the exception of a renewable contract firmed with a non-renewable resource. In that case, the blend of the two must meet the EPS, rather than the individual resources/units.

Do you agree with this approach? Why or why not? In your response, present your view of the relative advantages and disadvantages of the alternate approaches, and discuss your recommendation in the context of your answer on design priorities under Question #3.

10. In the context of the Staff Straw Proposal, how should the Commission treat partial contracts under the proposed EPS? An example discussed at the workshop was a “summer product” contract for power from a specified coal plant. For partial contracts, should the Commission look at how the facility is operating during the duration of the contract commitment, at the MWhs being purchased relative to the full year of facility operations, or consider other approaches? Would your proposed treatment of partial contracts result in an exemption under the 60% capacity factor rule, even if that underlying facility would be a “covered resource” under average annual operation? Why or why not?

11. The Staff Straw Proposal allows for an exemption from the standard for specified units of 25 MW or smaller, based on the size of the facility under construction or providing power under a contract. However, there would be no size exemption for unspecified contracts of any size. In commenting on this aspect of the Straw Proposal, please address the following:

- a. The MW level of the “small unit” exemption under this proposal. Do you support this exemption as proposed? Would you propose a different size exemption level and/or one specifically tied to projects qualifying under the self-generation incentives program? No exemption? Why or why not?
- b. Basing the exemption on MWs delivered to the grid. In determining eligibility for the size exemption, the Staff Straw Proposal would subtract out self-generated power that was not delivered to the grid.
 - i. Please indicate whether you agree with this approach to determining the size exemption, why or why not?
 - ii. If the Commission adopts this approach, what type of information (and source of data) would need to be presented for the Commission to determine the amount of expected self-generation to subtract from the unit size?
- c. Basing the exemption on the size of the unit being constructed or underlying a unit-specified contract, rather than the size of the contract. Please discuss the relative advantages and disadvantages of these alternate approaches to a size exemption, and indicate which you would recommend, should the Commission determine that a size exemption would be appropriate. (You may refer to your answer to the related Question 7, as appropriate).
- d. No size exemption for any unspecified contracts. Do you support this approach? Why or why not?

12. Under the Staff Straw Proposal, the Commission would develop two separate standards for covered resources: 1) a “moderate” EPS to apply to existing resources and repowering and 2) a “high” EPS to apply to new resources. Both would be based on the performance of a combined-cycle gas turbine (CCGT). Please address the following questions in your comments on this approach:

- a. Do you agree in concept with a dual standard as outlined in the Staff Straw Proposal, why or why not?
- b. If the Commission adopted this approach, what performance standard do you recommend for the “moderate” and “high” EPS? Express your answer in terms of heat rates as a proxy for GHG emission rates. Explain why you chose these levels, and the source of data/calculations you used to develop them.
- c. If instead you recommend a single EPS based on the performance of a CCGT for all new commitments (whether to new resources, existing or repowered facilities), provide your recommended performance

standard (expressed as a heat rate), explain why you chose this level, and the source of data/calculations you used to develop it.

- d. In responding to b. and c. above, be specific as to how you developed your CCGT reference standard and the data sources/calculations used. For example, did you base it on the expected performance of a modern CCGT newly placed in service, or at the end of its useful life, or an average of emissions from existing CCGTs, or another approach?
- e. If you have alternate or additional recommendations for the EPS standard and calculation, please submit them.

13. There was general agreement at the workshop that the Commission should allow credit for cogeneration thermal load when applying the EPS to covered resources. This is reflected in the Staff Straw Proposal. Do you agree with this approach, why or why not?

If you have developed a specific formula for the calculation of such a credit, please provide it in an attachment to your post-workshop comments, or in a separate joint submittal at the same time (if you are joining in with other parties on this issue). Indicate whether it is consistent with methods used to credit thermal loads in other emissions regulations for cogeneration facilities, either in California or elsewhere.

14. Do you have a position on how to calculate the net emission rates from renewables (e.g., for waste-to-energy, geothermal resources) for the purpose of applying the EPS? If so, please present your views either in your individual post-workshop comments or jointly with other interested parties at the same time.

15. There was discussion during the workshop on how to address unspecified contracts, i.e., what imputed emissions factor to use. The following alternatives were identified:

- a. Western Energy Coordinating Council (WECC) system average;
- b. Appropriate geographic average (e.g., Northwest purchases represent different resources than purchases from the Southwest);
- c. California Energy Commission (CEC) "Net System Power" calculations;
- d. Default to coal emission rates.

Please discuss your recommended approach, and why. Be as specific as possible as to the source of the data (or specific numbers) you would use for this purpose.

16. The Staff Straw Proposal does not include offsets or market price safety valves under the interim EPS, but does provide for a case-by-case reliability "safety valve" review by the Commission. (See Appendix A). Please comment on this aspect of the proposal, and provide your recommendations.

17. From a policy perspective, please discuss whether energy service providers, qualifying facilities (QFs) and other jurisdictional load-serving entities (LSEs), including

multi-jurisdictional utilities, should be subject to an interim EPS along with PG&E, SCE and SDG&E, should the Commission decide to adopt one. Limit your comments to policy considerations, rather than legal argument.²⁵

If you have considered the issue of how the Commission would apply an interim EPS to multi-jurisdictional utilities, please present a protocol for allocating emissions among resources serving multiple states with your post-workshop comments.

18. If the Commission adopted an interim gateway EPS modeled after the Staff Straw Proposal, what documentation should it require “at the gate” with respect to 1) meeting the small size exemption, including amount of power delivered to the grid (for self-generation), 2) demonstrating whether the new commitment meets the “covered resource” definition or not, 3) claiming the cogeneration thermal load credit and 3) other requirements of the EPS?

Should there also be compliance requirements under this gateway approach (e.g., with respect to unspecified contracts), and if so, what should they be?

19. Staff Straw Proposal raises the issue of how to attribute emissions factors to renewable resources that have sold off their renewable energy credits (e.g., to municipal utilities) for the purpose of applying the EPS. There was some discussion of this “null power” issue at the workshop. Options discussed included imputing an emissions rate from the WECC region or from the region where the renewable power was located, or using the CEC’s “net system power” calculation as a default emissions rate. If you have a recommendation on this issue, please provide it in your comments.

20. Please comment on any other aspects of the Staff Straw Proposal and alternative EPS designs for Commission consideration that are not covered in your answers to previous questions.

21. As reiterated in Judge Gottstein’s September 30, 2006 notice to the service list, the utilities and other workshop participants agreed to prepare information/analysis on topics related to the threshold policy and implementation design considerations for an interim EPS. Some of this information will be available and distributed to the service list prior to the preparation of post-workshop comments.

As appropriate, please comment on how you have used this information in developing your post-workshop comments. What additional information/analysis do you believe would be useful to the Commission in considering the policy and implementation questions posed above?

²⁵ Legal briefs on jurisdiction and related issues are being filed separately.

Appendix H

Revised Staff Proposal

D. Revised Staff Proposal for an Interim EPS

10) Design Goals for the EPS

- a) Prevent backsliding and commitments that will make future GHG reductions more difficult
- b) Minimize costs to ratepayers and minimize the risk of long-term commitments that will raise the cost of future compliance costs
- c) Reliability:
 - i) short-term: do not force shutdown of essential facilities
 - ii) long-term: consider risks of relying on high emitting resources
- d) Administrative simplicity, regulatory certainty

11) Timeframe

- a) Coordinate with procurement proceeding, but adopt now
- b) Implement performance standard as interim measure for an unspecified period of time. CPUC will re-evaluate the program, including consideration of ending the program, when a GHG cap and trade system or other relevant policy (CPUC, state, regional, or other) is functioning.

12) To Which LSEs does the EPS apply?

- a) Apply to all jurisdictional LSEs (including ESPs and CCAs)
- b) Create ESP process to address ESP procurement related to this program
- c) Don't delay pending legislation regarding publicly-owned utilities
- d) Develop a filing/approval process for multi-jurisdictional utilities (MJUs), including a protocol for allocating emissions among resources serving multiple states. Consideration given to MJUs that have prior approvals from other jurisdictions for integrated resource plans (IRP) that include adequate provisions for climate change

13) Program Screens

- a) The EPS standard will be applied on a "gateway" basis, at the time a LSE's commitment (build or buy) is proposed.
- b) The standard will be applied to the reasonably projected emission rate (lbs of CO₂ per MWh) from the supply source over the term of the commitment
- c) "Covered resources" are resources with a reasonably projected average annual capacity factor of 60% or greater.

14) Covered Power Sources

- a) Applied to all new utility commitments, including:
 - i) utility owned new generation,
 - ii) repowered facilities
 - iii) new and renewal contracts for power

- b) All new and renewal contracts and commitments in “covered resources” of five years or longer
- c) Applied to baseload and intermediate or “shaping” facilities with reasonably anticipated annual average capacity factor of 60% or greater
- d) Size threshold:
 - i) For specified facilities (built or under contract): 25 MW or greater commitment (e.g. contract size) delivered to the grid;
 - ii) For unspecified resource/facilities under contract: 25 MW or greater delivered to the grid under contract commitment.
 - iii) For either specified or unspecified commitments: a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration.²⁶ Multiple contracts with the same supplier, likely resource, or known facility are considered to be a single commitment, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.

We recognize that some professional judgment is required to determine when certain contractual commitments are “related” or “similar” so as to trigger review as a single commitment. However this is a common enough problem in environmental regulation and utility prior review programs, and we expect a professional rule of reasonableness to govern its application here. LSEs that are in doubt as to the application of the Rule to new long-term commitments can disclose their contracting patterns to the Commission and seek a jurisdictional determination under the Rule.

- e) Application to Qualifying Facilities (QFs) to be determined based upon CPUC review of legal briefs and in accordance with PURPA.
- f) Facilities used for self-generation are covered if they are reasonably expected to supply power to the grid above the threshold levels (size, duration, and capacity factor) set in the Rule for other facilities. Credit against emission rates for co-generation thermal loads will be permitted on a case-by-case basis upon a showing of the percentage of facility’s useful thermal load.
- g) Renewables compliant with the RPS are exempt, unless combined with firming resources. In the case of contracts with firming resources, see below.
- h) Reliability exemptions may be permitted, and will be considered on a case-by-case basis

15) What is the Standard and How Determined?

²⁶ Similar and related commitments should be considered cumulatively with respect to size, capacity factor, and duration. For example, two contracts with a baseload facility, each for 40% of the hours of the year, must be seen as the equivalent of a single commitment with an expected capacity factor of 80%. A contract for a four-year term, linked to a contract for the following 4 years, must be seen as a single commitment for eight years.

- a) Emissions standards based upon CCGT performance at ISO levels.
 - i) One standard for all covered facilities: equal to a high-performing new CCGT as discussed in the data request. The standard limit is 1000 lbs CO₂/MWh.
- b) Potential R&D exemption on a case-by-case basis for higher emitting facilities. One example might be an advanced coal facility that has an equal or better emission rate than the estimated IGCC average heat rate and emissions²⁷, and that has or will have in a reasonable period of time the capacity and existing plan to capture and store carbon dioxide as described in the GHG Performance Standard Policy Statement.

16) Application of the standard to units and contracts

- a) Single unit specific contracts: contracted unit must qualify
- b) Multi-unit contracts: each covered unit must qualify
- c) Baseload renewable product with a firming fossil unit(s) that qualifies as a “covered resource”: baseload blend average of all covered facilities (renewable and fossil). If firming unit is unspecified impute appropriate emissions factor.
- d) Null renewable power treated same as unspecified power. REC-covered power treated as renewable.
- e) Unspecified resource contracts: apply CEC “Net System Power” average. This is the statewide system average of the leftover energy in the system that is not claimed- includes in and out of state power, and anything that is not claimed by a CA utility, and is the most representative option reflecting CA LSE procurement activities. All LSEs would use the same average emissions factor, regardless of location in the state.
- f) For either specified or unspecified commitments: as discussed above in 5)d.iii., a series of related contracts with the same supplier, likely resource, or known facility, or a series of related or similar contracts with separate sources must be considered as a single commitment in size, capacity factor, and duration. Multiple contracts with the same supplier, likely resource, or known facility are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be considered in violation of the performance and subject to penalty and enforcement.
- g) A series of related or similar contracts, regardless of size, that appear to “slice and dice” procurement commitments are not permitted to avoid the standards of the EPS. Related contracts must be considered together as a bulk contract. Multiple contracts with the same supplier, likely resource, or known facility, are considered to be one bulk contract, and must be reviewed as such. Such multiple contract activities must be disclosed by the utilities to the CPUC in order to eliminate “slicing and dicing” of large contracts intended to avoid or manipulate the gateway screening process. Utilities that do not disclose such activities will be

²⁷ In the response to Data Request Q3, parties indicated an average heat rate of 8630 btu/kWh and emissions rate of 1770 lb CO₂/MWh for IGCC facilities.

considered in violation of the performance and subject to penalty and enforcement.

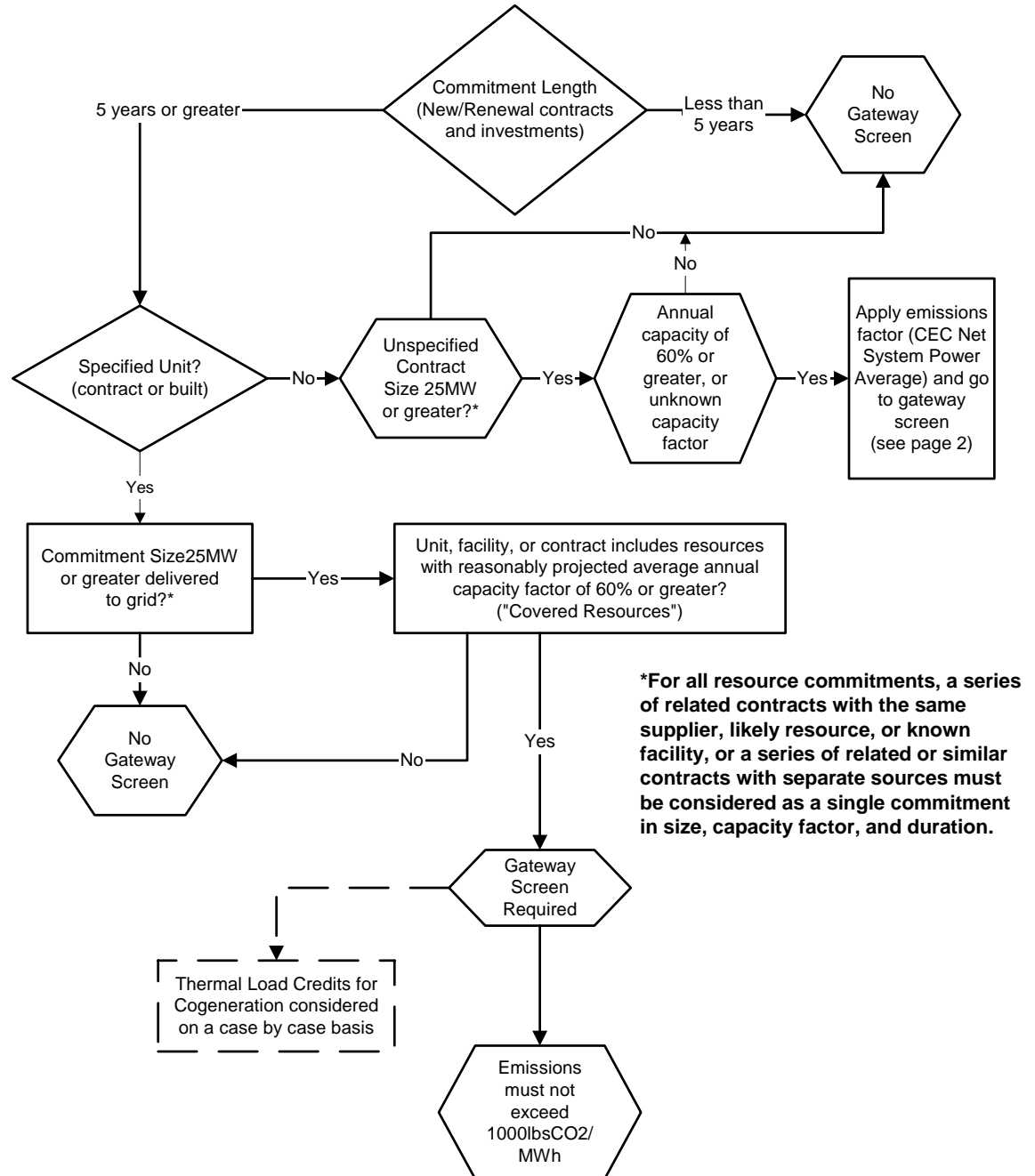
17) Monitoring and Enforcement

- a) CPUC gateway review with documentation and approval required prior to finalizing contract or commitment to construct

18) Offsets, Safety Valves, and other flexibility devices

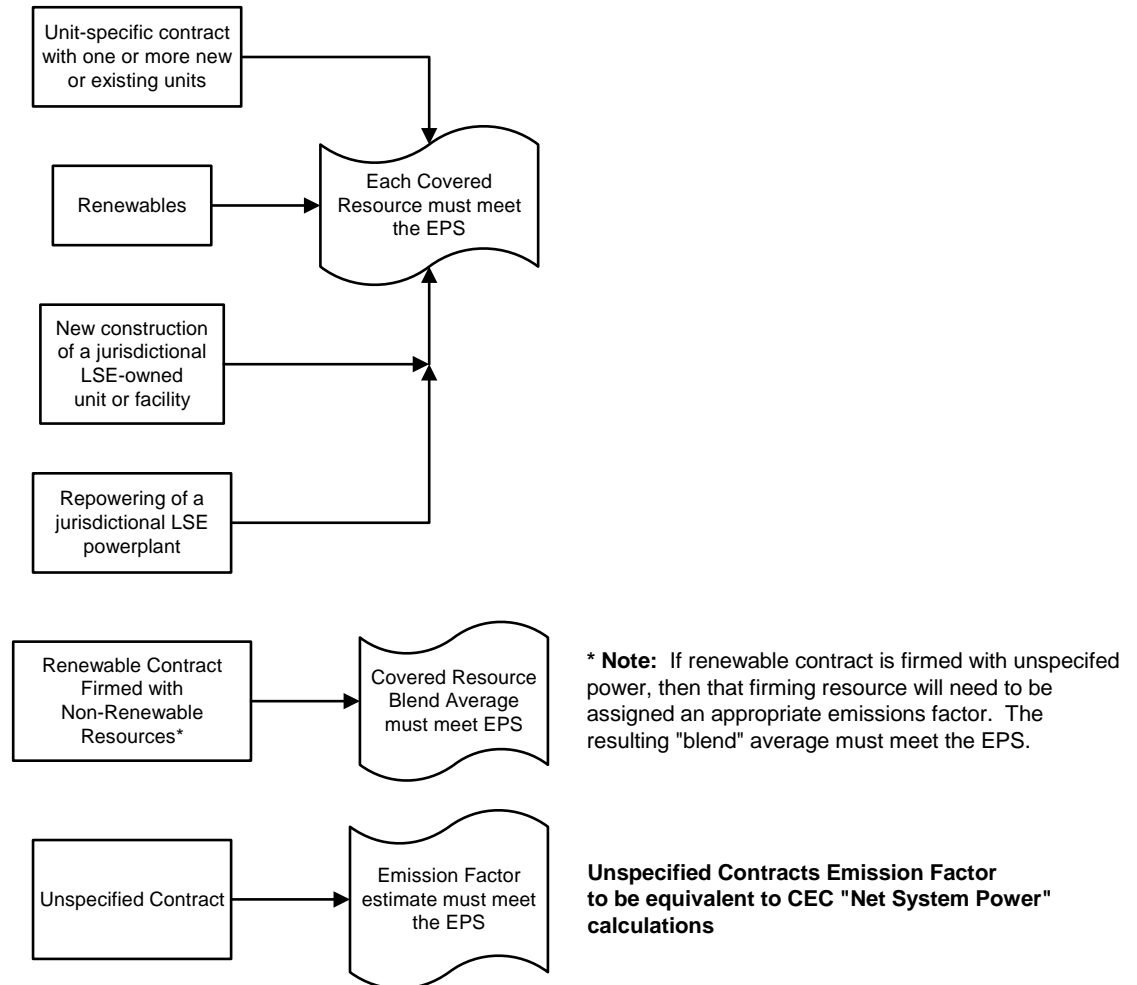
- a) No offsets or market price safety valves
- b) Case-by-case exemption for reliability only considered upon application and CPUC review.

Revised EPS Screen – Covered Commitments

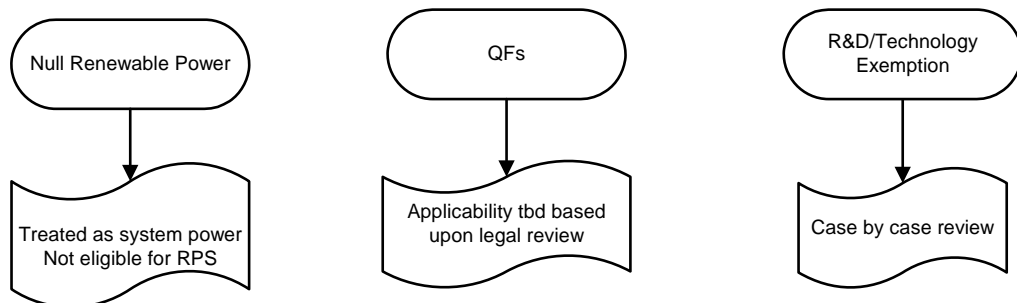


Emissions standards based upon CCGT performance
for facilities built in the last 25 years: 1000lbsCO₂/MWh

Revised Contract and Unit Specific Requirements to Meet EPS



Other Issues



Appendix I

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BILL NUMBER: SB 1368 ENROLLED
BILL TEXT

PASSED THE SENATE AUGUST 31, 2006
PASSED THE ASSEMBLY AUGUST 30, 2006
AMENDED IN ASSEMBLY AUGUST 30, 2006
AMENDED IN ASSEMBLY AUGUST 24, 2006
AMENDED IN ASSEMBLY AUGUST 21, 2006
AMENDED IN ASSEMBLY AUGUST 7, 2006
AMENDED IN ASSEMBLY JUNE 22, 2006
AMENDED IN SENATE APRIL 24, 2006

INTRODUCED BY Senator Perata
(Coauthor: Assembly Member Levine)

FEBRUARY 21, 2006

An act to add Chapter 3 (commencing with Section 8340) to Division 4.1 of the Public Utilities Code, relating to electricity.

LEGISLATIVE COUNSEL'S DIGEST

SB 1368, Perata Electricity: emissions of greenhouse gases.

(1) Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law authorizes the PUC to establish rules for all public utilities, and the Legislature has established procedures for rulemaking proceedings before the PUC. Existing law requires the PUC to review and adopt a procurement plan and a renewable energy procurement plan for each electrical corporation pursuant to the California Renewables Portfolio Standard Program.

Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission) to certify eligible renewable energy resources, to design and implement an accounting system to verify compliance with the renewables portfolio standard by retail sellers, and to allocate and award supplemental energy payments to cover the above-market costs of electricity generated by eligible renewable energy resources.

Under existing law the governing board of a local publicly owned electric utility is responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement. Existing law requires the governing board of a local publicly owned electric utility to report certain information relative to renewable energy resources to its customers.

Existing law defines an "electric service provider" as an entity that offers electrical service to customers within the service territory of an electrical corporation, excluding electrical corporations, local publicly owned electric utilities, and certain cogenerators. Provisions of the existing Public Utilities Act restructuring the electrical services industry require that electric

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service providers register with the PUC and require the PUC to authorize and facilitate direct transactions between electric service providers and retail end-use customers. However, other existing law suspends the right of retail end-use customers other than community aggregators, to acquire service through a direct transaction, until the Department of Water Resources no longer supplies electricity under that law.

Existing law defines a "community choice aggregator" and authorizes customers to aggregate their electric loads as members of their local community with community choice aggregators.

The existing restructuring of the electrical industry within the Public Utilities Act provides for the establishment of an Independent System Operator (ISO) as a nonprofit public benefit corporation. Existing law requires the ISO to ensure efficient use and reliable operation of the transmission grid consistent with achieving planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the American Electric Reliability Council.

Under existing law, the State Air Resources Board, the Energy Commission, and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would prohibit any load-serving entity, as defined, and any local publicly owned electric utility, from entering into a long-term financial commitment, as defined, unless any baseload generation, as defined, complies with a greenhouse gases emission performance standard. The bill would require the PUC, by February 1, 2007, through a rulemaking proceeding and in consultation with the Energy Commission and the State Air Resources Board, to establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities. The bill would require the Energy Commission, by June 30, 2007, at a duly noticed public hearing and in consultation with the PUC and the State Air Resources Board, to establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities. The bill would require that the greenhouse gases emission performance standard not exceed the rate of emissions of greenhouse gases for combined-cycle natural gas, as defined, baseload generation. The bill would prohibit the PUC from approving any long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term commitment complies with the greenhouse gases emission performance standard. The bill would authorize the PUC to review any long-term financial commitment proposed to be entered into by an electric service provider or community choice aggregator in order to enforce the bill's requirements. The bill would require the PUC to adopt rules to enforce these requirements for load-serving entities and would require the PUC to adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the greenhouse gases emission performance standard. The bill would require the PUC, through a rulemaking proceeding and in consultation with the Energy Commission and the State Air Resources Control Board, to reevaluate and continue, modify, or replace the greenhouse gases emissions performance standard when an enforceable greenhouse gases emissions

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limit is established and in operation, that is applicable to load-serving entities.

The bill would require the Energy Commission to adopt regulations for the enforcement of the greenhouse gases emission performance standard with respect to a local publicly owned electric utility. The bill would require the Energy Commission, in a duly noticed public hearing and in consultation with the PUC and the State Air Resources Board, to reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities.

(2) Under existing law, a violation of the Public Utilities Act or an order or direction of the commission is a crime.

Because certain of the provisions of this bill are within the act and require action by the commission to implement its requirements, a violation of these provisions would impose a state-mandated local program by creating a new crime.

(3) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. The Legislature finds and declares all of the following:

(a) Global warming will have serious adverse consequences on the economy, health, and environment of California.

(b) The Governor, in Executive Order S-3-05, has called for the reduction of California's emission of greenhouse gases to 1990 levels by 2020.

(c) Over the past three decades, the state has taken significant strides towards implementing an environmentally and economically sound energy policy through reliance on energy efficiency, conservation, and renewable energy resources in order to promote a sustainable energy future that ensures an adequate and reliable energy supply at reasonable and stable prices.

(d) To the extent energy efficiency and renewable resources are unable to satisfy increasing energy and capacity needs, the Energy Action Plan II establishes a policy that the state will rely on clean and efficient fossil fuel fired generation and will "encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the state's energy priorities."

(e) California's investor-owned electric utilities currently have long-term procurement plans that include proposals for making new long-term financial commitments to electrical generating resources over the next decade, which will generate electricity while producing emissions of greenhouse gases for the next 30 years or longer. New long-term financial commitments to zero- or low-carbon generating resources should be encouraged.

(f) The Public Utilities Commission (PUC) and State Energy Resources Conservation and Development Commission (Energy Commission)

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both have concluded, and the Legislature finds, that federal regulation of emissions of greenhouse gases is likely during this decisionmaking timeframe.

(g) It is vital to ensure all electricity load-serving entities internalize the significant and underrecognized cost of emissions recognized by the PUC with respect to the investor-owned electric utilities, and to reduce California's exposure to costs associated with future federal regulation of these emissions.

(h) The establishment of a policy to reduce emissions of greenhouse gases, including an emissions performance standard for all procurement of electricity by load-serving entities, is a logical and necessary step to meet the goals of the Energy Action Plan II and the Governor's goals for reduction of emissions of greenhouse gases.

(i) A greenhouse gases emission performance standard for new long-term financial commitments to electrical generating resources will reduce potential financial risk to California consumers for future pollution-control costs.

(j) A greenhouse gases emission performance standard for new long-term financial commitments to electric generating resources will reduce potential exposure of California consumers to future reliability problems in electricity supplies.

(k) In order to have any meaningful impact on climate change, the Governor's goals for reducing emissions of greenhouse gases must be applied to the state's electricity consumption, not just the state's electricity production.

(l) The 2005 Integrated Energy Policy Report adopted by the Energy Commission recommends that any greenhouse gases emission performance standard for utility procurement of baseload generation be set no lower than levels achieved by a new combined-cycle natural gas turbine.

(m) As the largest electricity consumer in the region, California has an obligation to provide clear guidance on performance standards for procurement of electricity by load-serving entities.

SEC. 2. Chapter 3 (commencing with Section 8340) is added to Division 4.1 of the Public Utilities Code, to read:

CHAPTER 3. Greenhouse Gases Emission Performance Standard for Baseload Electrical Generating Resources

8340. For purposes of this chapter, the following terms have the following meanings:

(a) "Baseload generation" means electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent.

(b) "Combined-cycle natural gas" with respect to a powerplant means the powerplant employs a combination of one or more gas turbines and steam turbines in which electricity is produced in the steam turbine from otherwise lost waste heat exiting from one or more of the gas turbines.

(c) "Community choice aggregator" means a "community choice aggregator" as defined in Section 331.1.

(d) "Electrical corporation" means an "electrical corporation" as defined in Section 218.

(e) "Electric service provider" means an "electric service provider" as defined in Section 218.3, but does not include corporations or persons employing cogeneration technology or producing electricity from other than a conventional power source

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consistent with subdivision (b) of Section 218.

(f) "Energy Commission" means the State Energy Resources Conservation and Development Commission.

(g) "Greenhouse gases" means those gases listed in subdivision (h) of Section 42801.1 of the Health and Safety Code.

(h) "Load-serving entity" means every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state.

(i) "Local publicly owned electric utility" means a "local publicly owned electric utility" as defined in Section 9604.

(j) "Long-term financial commitment" means either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation.

(k) "Output-based methodology" means a greenhouse gases emission performance standard that is expressed in pounds of greenhouse gases emitted per megawatthour and factoring in the useful thermal energy employed for purposes other than the generation of electricity.

(l) "Plant capacity factor" means the ratio of the electricity produced during a given time period, measured in kilowatthours, to the electricity the unit could have produced if it had been operated at its rated capacity during that period, expressed in kilowatthours.

(m) "Powerplant" means a facility for the generation of electricity, and includes one or more generating units at the same location.

(n) "Zero- or low-carbon generating resource" means an electrical generating resource that will generate electricity while producing emissions of greenhouse gases at a rate substantially below the greenhouse gas emission performance standard, as determined by the commission.

8341. (a) No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the Energy Commission, pursuant to subdivision (e), for a local publicly owned electric utility.

(b) (1) The commission shall not approve a long-term financial commitment by an electrical corporation unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission pursuant to subdivision (d).

(2) The commission may, in order to enforce the requirements of this section, review any long-term financial commitment proposed to be entered into by an electric service provider or a community choice aggregator.

(3) The commission shall adopt rules to enforce the requirements of this section, for load-serving entities. The commission shall adopt procedures, for all load-serving entities, to verify the emissions of greenhouse gases from any baseload generation supplied under a contract subject to the greenhouse gases emission performance standard to ensure compliance with the standard.

(4) In determining whether a long-term financial commitment is for baseload generation, the commission shall consider the design of the powerplant and the intended use of the powerplant, as determined by the commission based upon the electricity purchase contract, any

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certification received from the Energy Commission, any other permit or certificate necessary for the operation of the powerplant, including a certificate of public convenience and necessity, any procurement approval decision for the load-serving entity, and any other matter the commission determines is relevant under the circumstances.

(5) Costs incurred by an electrical corporation to comply with this section, including those costs incurred for electricity purchase agreements that are approved by the commission that comply with the greenhouse gases emission performance standard, are to be treated as procurement costs incurred pursuant to an approved procurement plan and the commission shall ensure timely cost recovery of those costs pursuant to paragraph (3) of subdivision (d) of Section 454.5.

(6) A long-term financial commitment entered into through a contract approved by the commission, for electricity generated by a zero- or low-carbon generating resource that is contracted for, on behalf of consumers of this state on a cost-of-service basis, shall be recoverable in rates, in a manner determined by the commission consistent with Section 380. The commission may, after a hearing, approve an increase from one-half to 1 percent in the return on investment by the third party entering into the contract with an electrical corporation with respect to investment in zero- or low-carbon generation resources authorized pursuant to this subdivision.

(c) (1) The Energy Commission shall adopt regulations for the enforcement of this chapter with respect to a local publicly owned electric utility.

(2) The Energy Commission may, in order to ensure compliance with the greenhouse gases emission performance standard by local publicly owned electric utilities, apply the procedures adopted by the commission to verify the emissions of greenhouse gases from baseload generation pursuant to subdivision (b).

(3) In determining whether a long-term financial commitment is for baseload generation, the Energy Commission shall consider the design of the powerplant and the intended use of the powerplant, as determined by the Energy Commission based upon the electricity purchase contract, any certification received from the Energy Commission, any other permit for the operation of the powerplant, any procurement approval decision for the load-serving entity, and any other matter the Energy Commission determines is relevant under the circumstances.

(d) (1) On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the Energy Commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.

(2) In determining the rate of emissions of greenhouse gases for baseload generation, the commission shall include the net emissions resulting from the production of electricity by the baseload

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generation.

(3) The commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gases emitted by the facility in the production of both electrical and thermal energy.

(4) In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the commission shall consider net emissions from the process of growing, processing, and generating the electricity from the fuel source.

(5) Carbon dioxide that is injected in geological formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the powerplant in determining compliance with the greenhouse gases emissions performance standard.

(6) In adopting and implementing the greenhouse gases emission performance standard, the commission, in consultation with the Independent System Operator shall consider the effects of the standard on system reliability and overall costs to electricity customers.

(7) In developing and implementing the greenhouse gases emission performance standard, the commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(8) In developing and implementing the greenhouse gases emission performance standard, the commission shall consider and act in a manner consistent with any rules adopted pursuant to Section 824a-3 of Title 16 of the United States Code.

(9) An electrical corporation that provides electric service to 75,000 or fewer retail end-use customers in California may file with the commission a proposal for alternative compliance with this section, which the commission may accept upon a showing by the electrical corporation of both of the following:

(A) A majority of the electrical corporation's retail end-use customers for electric service are located outside of California.

(B) The emissions of greenhouse gases to generate electricity for the retail end-use customers of the electrical corporation are subject to a review by the utility regulatory commission of at least one other state in which the electrical corporation provides regulated retail electric service.

(e) (1) On or before June 30, 2007, the Energy Commission, at a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. The greenhouse gases emission performance standard established by the Energy Commission for local publicly owned electric utilities shall be consistent with the standard adopted by the commission for load-serving entities. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.

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(2) The greenhouse gases emission performance standard shall be adopted by regulation pursuant to the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

(3) In determining the rate of emissions of greenhouse gases for baseload generation, the Energy Commission shall include the net emissions resulting from the production of electricity by the baseload generation.

(4) The Energy Commission shall establish an output-based methodology to ensure that the calculation of emissions of greenhouse gases for cogeneration recognizes the total usable energy output of the process, and includes all greenhouse gas emitted by the facility in the production of both electrical and thermal energy.

(5) In calculating the emissions of greenhouse gases by facilities generating electricity from biomass, biogas, or landfill gas energy, the Energy Commission shall consider net emissions from the process of growing, processing, and generating the electricity from the fuel source.

(6) Carbon dioxide that is captured from the emissions of a powerplant and that is permanently disposed of in geological formations in compliance with applicable laws and regulations, shall not be counted as emissions from the powerplant.

(7) In adopting and implementing the greenhouse gases emission performance standard, the Energy Commission, in consultation with the Independent System Operator, shall consider the effects of the standard on system reliability and overall costs to electricity customers.

(8) In developing and implementing the greenhouse gases emission performance standard, the Energy Commission shall address long-term purchases of electricity from unspecified sources in a manner consistent with this chapter.

(9) In developing and implementing the greenhouse gases emission performance standard, the Energy Commission shall consider and act in a manner consistent with any rules adopted pursuant to Section 824a-3 of Title 16 of the United States Code.

(f) The Energy Commission, in a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to local publicly owned electric utilities.

(g) The commission, through a rulemaking proceeding and in consultation with the Energy Commission and the State Air Resources Board, shall reevaluate and continue, modify, or replace the greenhouse gases emission performance standard when an enforceable greenhouse gases emissions limit is established and in operation, that is applicable to load-serving entities.

SEC. 3.

No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

FINAL